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ACID RAIN CONTROL TECHNOLOGIES

HEARINGS

BEFORE THE

SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION

OF THE

COMMITTEE ON

ENVIRONMENT AND PUBLIC WORKS

UNITED STATES SENATE

ONE HUNDRETH CONGRESS

FIRST SESSION

MARCH 4 AND 11, 1987

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ACID RAIN CONTROL TECHNOLOGIES

Existing and Emerging Acid Rain Control Technologies

WEDNESDAY, MARCH 4, 1987

U.S. SENATE,
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS,
SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION,
Washington, DC.

The subcommittee met, pursuant to notice, at 9:30 a.m., in Room SD-406, Dirksen Senate Office Building, Hon. George J. Mitchell (chairman of the subcommittee) presiding.

Present: Senators Mitchell, Baucus, Stafford, Chafee, Warner, Pressler, Durenberger, and Simpson.

OPENING STATEMENT OF HON. GEORGE J. MITCHELL, U.S. SENATOR FROM THE STATE OF MAINE

Senator MITCHELL. Good morning, ladies and gentlemen. This is the second in a series of hearings being held by this committee on the subject of acid rain. Today's hearing will focus on existing and emerging acid rain control technologies. Next week we will focus on the clean coal technology program, and the Administration's implementation of the U.S.-Canada Joint Envoys' report.

There will be two hearings on this and related subjects later this month to discuss ozone and carbon monoxide non-attainment and health, and the efforts of State and local government to meet the December 31, 1987 deadline.

The major stumbling block to an acid rain control program has been and remains the cost of such a program. The cost of pollution control utilities and the cost in unemployment to high-sulfur coal miners. Acid rain control technology can help play a pivotal role in resolving these problems.

The available technologies have improved dramatically since I first introduced acid rain legislation 7 years ago. The cost of scrubbers is declining. Coal gasification, such as that found at the Cool Water plant in California, and fluidized bed combustion, once topics only for drawing board discussions are now in commercial operation.

The technologies are available today to effectively control sulfur dioxide and nitrogen oxides. We should continue to explore even more effective ways of reducing such costs through efforts such as the clean coal program. This should not replace an acid rain control program, but it should complement it.

Control technologies are useful as a way to emissions reductions which are necessary to control acid rain. Control technologies are useful as a way to achieve those necessary reductions.

I look forward to hearing from the panelists this morning and especially want to welcome the distinguished majority leader, who has played an important role on this issue and who has vigorously and, as he always does, most ably represented the interests of his constituents.

The people of West Virginia are fortunate, Mr. Leader, to have you as their representative in the Senate, and we look forward to hearing from you this morning as always.

STATEMENT OF HON. ROBERT C. BYRD, U.S. SENATOR FROM THE STATE OF WEST VIRGINIA

Senator BYRD. Mr. Chairman I thank you for your kind words this morning and may I say, not as a pleasantry, but feeling very sincere in saying this, that you equally represent your people, and you work hard for them, and you believe in what you are doing and you believe in the rightness of the approach that you are taking. I respect your viewpoint, and I respect the reasoning behind your position in this matter.

With the record showing that great respect that I have for you and for all Senators and for people who believe that the approach that is taken, or would be taken by the legislation that has been introduced, is the right approach, I believe that we just have to come to the understanding that we just don't see things alike in this situation, which in itself indicates that there is not an area of absolute certitude here for any of us.

I compliment the subcommittee for the work it is doing and I appreciate very much the courtesy that you have shown me this morning, Mr. Chairman, by allowing me to begin at the first of the hearing.

I believe that new clean coal technologies must be developed and demonstrated in order to insure an energy future of abundant secure supplies at reasonable costs. Electricity is the engine of our economic growth and international competitiveness.

While energy security is the primary goal of clean coal technology research development, and demonstration, I also believe that the long term development and deployment of clean burning processes will lead to steady progress toward resolving the acid rain problem.

Since at least 1980, Congress has been debating what should be done about the acid rain emergency. For a decade we have been warned that without immediate and drastic control measures our lakes and our forests would be faced with impending doom.

Fortunately, in 1980 Congress put into place a massive acid rain research program. While the debate has raged, scientists have been carefully performing experiments and gathering information. The results will not be fully completed until the end of the decade, but we have already learned some things that have significant policy implications.

First of all, we have learned that it appears that lake acidification is not currently widespread. The lake surveys recently completed by the Environmental Protection Agency indicate that less than 1 percent of our eastern lakes and none of our western lakes are acidified.

Secondly, there is no trend analysis indicating that things have been getting worse or that they will get worse anytime soon. Thus there is no reason to believe that the problem will worsen if we do not reduce emissions.

Thirdly, it is not clear what role, if any, acid rain is playing in forest damage. There is still real danger that if we were to initiate controls on sulfur dioxide to help our forest we would be controlling the wrong pollutant. We are not facing "Environmental Armageddon." The important thing is to achieve steady progress in reducing emissions. Immediate, massive reductions at tremendous costs are not scientifically defensible.

Perhaps I would not insist that we should have scientific certainty if the impacts of the acid rain control legislation introduced so far were not so severe, but severe they are, indeed. Not only would these bills be expensive, socially disruptive, and injurious to our competitive position, but they could also harm the environment in the long run.

The time and the money that could be spent developing and deploying newer and cleaner coal technologies, may instead be diverted to retrofitting equipment or switching coals in order to meet the immediate requirements that these bills would impose.

Technologies now under development can do better than the current New Source Performance Standards for both sulfur dioxide and nitrogen oxide. For example, integrated gasification combined cycle has demonstrated sulfur dioxide removal levels of over 99 percent. A demonstration program resulting in wide deployment of this technology in new plants would drastically reduce long-term emissions of sulfur dioxide.

Currently proposed acid rain legislation, achieves near term reductions at the expense of the long-term. Given even conservative estimates for future electricity demand and generating capacity, we will need 100,000 to 200,000 megawatts of new capacity by the turn of the century. We must begin to demonstrate new clean technologies now so that they will be available to meet this future growth.

In testimony before the Senate Energy and Natural Resources Committee in June of last year, Kurt Yeager of the Electric Power Research Institute summarized the case against an acid rain control program that would retrofit flue gas scrubbers on existing high-sulfur coal-fired capacity.

He said:

> If the $200 billion necessary to implement the scrubber retrofit strategy over the remaining life of the affected plants were instead invested on new plants using advanced clean coal technologies, it would provide about half of the new generating capacity the Nation is likely to require during the next 30 years. Such an investment would provide superior environmental control, not only for sulfur oxides, but also for nitrogen oxides and solid waste, while improving the productivity and cost of power generation.

Proponents of control legislation have been debating for the past seven years how to achieve the largest emission reductions in the shortest possible timeframe, often without sufficient consideration for the economic disruption and energy policy implications of such a purchase.

In the meantime, I initiated a clean coal technology program that will achieve, among other things, long-term real reductions in emissions of acid rain precursors. The clean coal technology makes sense. It makes economic sense, environmental sense, and energy policy sense.

In November of 1984, the Congress created a $750 million clean coal technology reserve over the strong objections of the Reagan Administration. The reserve is to be used to co-fund clean coal technology demonstrations with the private sector. Despite the Administration's less than enthusiastic implementation of the first round of the program, it has achieved impressive results. The industry response has been overwhelming.

The Department of Energy received 176 submissions involving 159 specific projects from sponsors in 29 states. Industry identified more than one dozen technologies, which were near commercialization, but required large-scale demonstration before they would become acceptable to the marketplace.

The submissions indicated that industry was in fact willing to spend very significant private funds, often exceeding 50 percent of the cost of a project. In July, 1986, the Department of Energy selected 9 projects and 14 alternatives to participate in the program. Negotiations have been completed on two of the nine projects thus far and the rest are expected to be completed soon.

Under the first round of the program DOE will spend $400 million with an additional $600 million being put up by industry and states. The nine projects represent a variety of technologies for a variety of applications. For example, American Electric Power will repower its facility in Brilliant, Ohio, with a 70 megawatt pressurized fluidized bed combustion combined cycle plant. The project is estimated to cost $167 million with the Federal Government's share being $60 million.

The company has agreed to absorb any cost overruns and has agreed to a plan to repay the Federal contribution. Construction is scheduled to begin by the end of 1987 with the three year operation phase starting in early 1990. Removal efficiencies better than NSPS levels are expected for both sulfur dioxide and nitrogen oxide.

As another example, Coal Tech Corporation will demonstrate an advanced horizontal cyclone combustor with integrated sulfur, nitrogen and ash control systems. The combustor will be a 30 million Btu/hr industrial boiler. Not only will this project facilitate commercialization of new industrial boiler technologies, it will also provide an excellent basis for scale up to larger utility boilers. Over 90 percent sulfur dioxide removal and 70 to 80 percent nitrogen oxide removal is anticipated, thus meeting or exceeding the NSPS levels.

This project is a true cooperative effort. The Pennsylvania Energy Authority is contributing $200,000. Pennsylvania Power and Light is providing test coals, and Keeler Boiler Manufacturing Company is providing the boiler and test site. The total cost of the project is estimated to be $786,000, of which 50 percent will be paid by DOE.

In the past year, the Administration has switched from staunchly opposing to warmly embracing the Clean Coal Program. I will not speculate on what might have caused this rather dramatic turnaround, but I welcome this new-found support.

The conversion is so complete in fact that the Administration is now touting the Clean Coal Program as the down payment on the implementation of the recommendations of the Canadian-American joint special envoy's report on acid rain. In fact, the first phase of the program was authorized and funds for it were appropriated well before the envoy's report was published.

Phase I was designed to facilitate the use of coal in a wide variety of situations. Some of these applications, by chance, happened to conform to a strict reading of the Louis/Davis Report. For those projects conforming to the criteria, emission reductions will be achieved more cost-effectively than would have been the case if existing scrubber technology had been employed.

This past summer, Congress directed DOE to solicit industry interest in a second round of the program targetted to projects that retrofit, repower or modernize existing facilities. Industry demonstrated its continuing strong commitment to the Clean Coal Program, by submitting 140 project proposals in response to the second DOE solicitation.

Eighty-three of the 140 responses included cost estimates for their projects totalling $3.5 billion. Based on the cost estimates submitted, the total value of the 140 projects including the Federal Government's contribution would be $6 billion. Almost all of these projects would meet the specific criteria in the special envoy's report as well as the broader objectives of the clean coal reserve.

I was encouraged to see that the Administration has requested a multiyear increase in funding for the Department of Energy's Clean Coal Program. With this new-found support, I expect that the Federal Government will make substantial progress in expanding the use of coal to power our nation's economic growth.

Through this effort we can move to the forefront of the development of clean coal technology for domestic as well as international markets. We will improve the environment, while making America more competitive.

I believe that with continued support from both the Congress and the Executive Branch, the Clean Coal Program will ensure that we will have long-term domestic supplies of clean energy. However, the penetration of new technologies into the private sector can sometimes be a slow process. Companies are always risk-averse, but regulated firms, such as electric utilities, are particularly wary of taking technological risks.

The Clean Coal Program, although only midway through its demonstration phase, is an excellent way to encourage utilities to take such risks. The next step is to develop a deployment strategy that will provide the additional financial and regulatory incentives required to commercialize these technologies.

I believe that the Clean Coal technology program makes sense. It will achieve, among other things, long-term real reductions in emissions of acid rain precursors. It can accomplish these goals without causing the severe economic impacts associated with the acid rain control bills before the committee.

What are these impacts?

S. 300 is a very stringent and expensive bill. It would go into effect at the earliest date. ICF, Inc., estimated that the bill would cost over $20 billion per year when fully implemented. It would force every coal-fired powerplant in the country to either shut down or put on stringent controls.

These controls would not only include costly scrubbers, but also selective catalytic reduction, a technology that is not even required in this country on new sources. The 1991 deadline, the earliest of any bill, would clearly preclude the use of innovative technology.

The bill would cost West Virginia powerplants $1 billion a year, and would increase State-wide average electricity rates by 29 percent. Some companies and residents would see even more severe increases.

According to a June, 1985, report by the Congressional Research Service, which was updated recently at my request:

> The core of West Virginia's industrial economy is electricity-intensive and the industrial base is not very broad.
>
> West Virginia's industrial position is therefore very sensitive to increases in the cost of electricity. Furthermore, West Virginia's primary metals and chemical industries—the core of the State's industrial base—may shoulder the majority of industry's share of acid rain control in the State.

For example, one major chemical manufacturer has estimated that under the Stafford, Mitchell, or Proxmire bills, power costs for the company could increase by $3.1 million to $5.4 million per year for its West Virginia operations. In addition, the manufacturer would have to make capital expenditures of $8 to $10 million to meet new nitrogen oxide standards for industrial boilers.

A major aluminum manufacturer would be forced to close its West Virginia smelter under any of the current proposals. The aluminum industry is particlarly vulnerable to electricity cost increases. The example of the West Virginia smelter could be replicated throughout the United States, thereby increasing our dependence on foreign imports.

Under S. 300, industrial electricity prices to energy-intensive midwestern firms would increase by 20 to 40 percent. The chlorine/caustics industry, for example, would face cost increases ranging from 16.5 to 31.5 percent of its product prices. Keep in mind that the rate impacts that undermine industrial competitiveness will not be confined to the midwest.

The problem would be national because many States export power to other regions. West Virginia, for example, exports 70 percent or 54 billion kilowatt hours, of the electric power generated within its borders to serve seven of the States: Ohio, Pennsylvania, Virginia, Maryland, Tennessee, New Jersey, and North Carolina.

These impacts should be of grave concern to the 100th Congress, because of its major commitment to improving the international competitiveness of American industry. Legislation such as S. 300 would be counterproductive to our major legislative goal.

S. 321, while somewhat less expensive than S. 300, would still be very costly. I commend the chairman of this subcommittee for including in his bill more reasonable nitrogen oxide provisions than those in S. 300. The sulfur dioxide provisions remain very expensive and the deadlines early enough to preclude many innovative technologies.

While often cheaper for the utility, the dollar savings from fuel switching would be achieved at a large human cost. Many coal miners would lose their jobs. Many of those miners live in my State. According to the CRS, large-scale coal switching would cause unemployment in northern West Virginia to increase by 17 percent.

I have a similar concern about S. 316, this bill would also result in massive coal switching. High-sulfur producers in northern Appalachia and the midwest could lose over 100 million tons of projected coal production by the year 2000.

Mr. Chairman, we stand at a crossroads. If we go in the direction outlined in the bills before the committee, it will mean that we will spend billions of dollars on out-of-date scrubber technology, drastically increase industrial and residential electricity rates, precipitate massive job disruption and add to our burgeoning trade deficit—all in the name of dealing with a problem that we do not fully understand.

On the other hand, if we take the path of clean coal technology demonstration and deployment, I believe that we will make steady progress toward meeting our energy and environmental needs while preserving the livelihoods of our citizens and the competitiveness of our American industry.

That completes my prepared statement, Mr. Chairman, and I thank you again.

Senator MITCHELL. Mr. Leader, thank you very much for your statement. As usual, a very well prepared and forceful statement of your position, and while as you noted at the outset, we do not agree on this issue, I have the greatest respect for your position.

I note the presence of Senator Stafford, the distinguished former Chairman of the committee. I would like to welcome him.

Senator, do you have any opening comments you would like to make.

Senator STAFFORD. Thank you, Mr. Chairman, I do not. I am here to listen and to learn this morning.

Senator MITCHELL. Do you have any questions for Senator Byrd?

Senator STAFFORD. No, I haven't.

Senator MITCHELL. I have no questions. Thank you very much, Senator. We do appreciate your statement very much.

Senator BYRD. I thank you, Mr. Chairman. I thank you, Senator Stafford. I ask permission, Mr. Chairman, to insert in the record some data that I think bears on this subject and I hope that it would be helpful to the committee in its consideration.

Senator MITCHELL. Without objection it will be done.

[The material referred to follows:]

Congressional Research Service
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Washington, D.C. 20540

February 18, 1987

TO : Senate Democratic Policy Committee
Attention: Judi Greenwald

FROM : Larry Parker Specialist
Environment and Natural Resources Policy Division

SUBJECT: Impact of S. 300 and S. 316 on Electricity-Intensive Industries

In response to your request, I have made some estimates of the impact of S. 300 and S. 316 on electricity-intensive industries. The estimates are based on a previous CRS report entitled "Acid Rain Legislation and Midwest Industry: A Mountain or a Mole Hill?" No attempt has been made to update the descriptions or assumptions of that analysis, except to calculate appropriate acid rain induced rate increases for S. 300 and S. 316.

Estimating Rate Increases from S. 300 and S. 316

As we discussed, EPA-funded ICF reports on S. 2203 and S. 2813 provide some electric rate approximations for examining S. 300 and S. 316, particularly S. 316.[1] However, because of changes in S. 2203 incorporated in S. 300 and ICF's method of analyzing S. 2203, the ICF report on S. 2203 probably overestimates the potential impact of S. 300. Hence, for accuracy, I believe the S. 300 scenario based on the ICF numbers should be called an "all

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[1] ICF Incorporated. Summary Findings of All Scrubbing/All NOx Control Analysis. Memorandum to Alex Cristofaro and Judi Greenwald, September 11, 1986. ICF Incorporated. Preliminary Forecasts: Proxmire Bill. Memorandum to Judi Greenwald, October 30, 1986.

FGD/SCR" scenario. [2] The ICF scenario for S. 2813 should be largely applicable to S. 316, which is the same as S. 2813 except that S. 316 has a tonnage cap on future emissions.

Thus, this memo uses two scenarios based on the EPA-funded reports: (1) a S. 316 scenario, and (2) an all FGD/SCR scenario. While these numbers are useful for the illustrative calculations of this memo, they are no substitute for site-specific analysis as done in part in the previous CRS report. All of the caveats discussed in that report apply to this memorandum.

Table 1 indicates the resulting rate increases in the year 2000 for the S. 316 and all FGD/SCR scenarios in seven States with electricity intensive industries. As indicated, the range produced by the S. 316 scenario is the same as that developed by CRS to analyze the impact of H.R. 3400 of the 98th Congress. This coincidence should not be taken too strongly. The previous CRS report did some site-specific work on individual utilities, utilities which tended to benefit directly from H.R. 3400's cost-sharing provisions. The numbers developed here are statewide averages, reflecting not only the specific utilities having electricity intensive industry, but also other utilities which may not be as affected by acid rain control. Indeed, based on the previous report, it seems likely that the average rate increases generated here for the S. 316 scenario underestimate in some cases the rate increase that the individual utilities having electricity-intensive industry load would experience.

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[2] The SCR part of ICF's analysis is probably accurate as the West Germans in all likelihood will demonstrate SCR on coal-fired boilers within the next few years. However, while the all FGD scenario may be correct in the long run for S. 300 and possibly for some individual States, the 0.9 lbs. of SO2 per million Btu interim standard is possible without FGD in some cases.

Table I: Projected Rate Increases from
S. 316 and All FGD/SCR Scenarios
(in mills per kwh)

STATE	S. 316 Scenario	All FGD/SCR Scenario
Illinois	1	8
Indiana	4	13
Kentucky	2	10
Missouri	3	11
Ohio	4	11
Tennessee	2	8
West Virginia	3	14

Sources: ICF Incorporated. Preliminary Forecasts: Proxmire Bill, October 30, 1986

ICF Incorporated. Summary Findings of All Scrubbing/All NOx Control Analysis, September 11, 1986.

U.S. Department of Energy. State Energy Price and Expenditure Report: 1970-1982. DOE/EIA-0376(82), April 1985.

Comparing the two scenarios, the all FGD/SCR scenario clearly raises rates more than the S. 316 scenario. This is not surprising as S. 316 would not require SCR to comply with its NOx requirement, and ICF projects only 12 gigawatts of FGD capacity installed. ICF projects 254 gigawatts of FGD installed in its all FGD/SCR scenario. The payoff for this additional cost is additional reductions of both SO2 and NOx over the S. 316 scenario.

Impact on Electricity Intensive Industries

In the previous CRS report, six electricity intensive industrial categories were examined: aluminum, iron and steel, chemical and allied products, primary zinc and copper, and basic glass. Table 2 breaks down these categories into the specific industries examined and in which States major facilities are located as identified by the report. The data presented are not comprehensive.

Table 2: Location of Major Electricity Intensive Facilities

STATE	Aluminum Smelters	Electric Arc Furnaces	Chlorine/ Caustics	Primary Zinc	Primary Copper	Glass Container*
Illinois	—	Yes	—	Yes	—	—
Indiana	**	Yes	Yes	—	—	—
Kentucky	Yes	Yes	Yes	—	—	—
Missouri	Yes	Yes	—	—	Yes	—
Ohio	Yes	Yes	Yes	—	—	—
Tennessee	***	Yes	Yes	Yes	—	—
W. Virginia	Yes	Yes	Yes	—	—	—

* CRS was unable to obtain data from glass associations. Individual companies and plants provided the data used in the analysis.

** The smelter in Indiana has self-generation facilities.

*** One of the two smelters in Tennessee owns 7 hydro electric units in North Carolina, the power from which the company exchanges with TVA to provide power to the smelter.

Source: See Parker, Larry B. and Holt, Alison. Acid Rain Legislation and Midwest Industry: A Mountain or a Mole Hill? CRS Report. June 6, 1985.

To calculate the estimated impact on product costs of increased electricity rates, the same methodology and assumptions used in the previous CRS report were employed. The rate increases shown in table 1 were used to estimate the impacts for the two scenarios.

The results are presented in table 3. As indicated, the impact of the all FGD/SCR scenario is substantially higher than the S. 316 scenario. The two industries that would be hardest hit would be aluminum and chlorine/-caustics. In both cases, the industries are engaged in international competition, particularly the aluminum industry. In 1985, the price of aluminum on the international market was about 50 cents a pound, compared with a rough average cost of 60-65 cents a pound for the two smelters in Kentucky. While chlorine and caustic soda do not directly compete on international markets because they cannot be shipped long distances economically, some derivatives can be.

For the other industries where energy costs are less important than for the aluminum and chlorine/caustic industries, the rate impacts may affect the competitive position of individual firms or plants. Most industry is price sensitive, and therefore, any increase in manufacturing costs hurts the competitiveness of a firm. This situation is complicated in the case of acid rain legislation as competitors within the same industry may experience different electricity rate increases, depending on which utility serves it. Because this memo uses average statewide costs, this disparity is hidden somewhat in these calculations. Hence, while a cost increase that is added to the product price on a specific facility resulting from acid rain legislation (or any other event) may be small, it may be sufficient for purchasers to shift to suppliers experiencing smaller cost increases and raising prices less. This puts the first facility in the position of either absorbing the different in costs increases, or losing some business.

Table 3: Estimated Impact on Selected Industries of Rate Increases
(as percentage of product price)

RATE INCREASE	Aluminum Smelters	Electric Arc Furnaces	Chlorine/ Caustics*	Primary Zinc	Primary Copper	Glass Container**
S.316 Scenario						
1 mill	—	0.1%	—	0.4%	--	0.2-0.3%
2 mills	2.5%	0.2%	4.0-4.5%	0.7%	—	0.3-0.5%
3 mills	3.8%	0.4%	6.0-6.8%	--	<0.1%	0.5-0.8%
4 mills	4.1%	0.5%	8.0-9.1%	--	—	0.7-1.0%
All FGD/SCR Scenario						
8 mills	10.0%	1.0%	16.5-18.1%	2.9%	0.2%	1.4-2.0%
10 mills	12.5%	1.2%	20.6-22.6%	--	--	1.5-2.5%
11 mills	13.8%	1.3%	22.7-24.9%	—	—	1.7-2.8%
13 mills	—	1.6%	26.8-29.4%	--	—	2.3-3.3%
14 mills	17.5%	1.7%	28.9-31.7%	--	--	2.5-3.5%

* The range depends on the cell technology used at the plant.

** Calculated in terms of percent of manufacturing costs, assuming electricity cost equals 10 percent of manufacturing costs. The range is based on two base case electricity prices of 40 and 60 mills per kwh.

Source: Rate increases are based on table 1. Other assumptions are contained in Parker, Larry B. and Holt, Alison. Acid Rain Legislation and Midwest Industry: A Mountain or a Mole Hill? CRS Report. June 6, 1985.

Senator MITCHELL. Mr. Leader, I want to say to you that ordinarily there would have been many members of the subcommittee here. The reason that they are not is that most of the members of this subcommittee, including Senator Stafford and I, are members of the Highway Conference, which is just at this moment convening on the House side.

We have been meeting on a regular basis, as you know, and the other members had to go to that conference, and several of them asked me to express to you their regret that they simply couldn't be in both places. Senator Stafford and I are going to have to go over there as soon as we finish this hearing.

Senator BYRD. Mr. Chairman, I thank you for that explanation. You indicated the same to me yesterday, and I commend you for the work that you are doing in that conference.

I think it is extremely important to the Nation that the conference be able to resolve the differences between the two Houses as quickly as possible because the new construction season is going to begin and our States are in dire need of the funding that is provided in that bill. I hope that at the earliest moment you will be able to resolve the problems there and again. I thank you very much.

Senator MITCHELL. Thank you, Mr. Leader.

I have a statement from Senator Lautenberg that will be entered into the record.

[Senator Lautenberg's statement follows:]

OPENING STATEMENT OF HON. FRANK R. LAUTENBERG, U.S. SENATOR FROM THE STATE OF NEW JERSEY

Mr. Chairman, I commend you for holding this hearing today about acid rain control technologies. I was pleased to join you in introducing legislation (S. 321) to control this problem. I look forward to working with you and others on the committee to address this pervasive threat to the Nation's health and environment.

100,000 tons of sulfur dioxide pollution is spewed out over our cities, forests, rivers, and lakes every day. Left unchecked, these emissions will increase in the years ahead.

In 1984, the Office of Technology Assessment reported that 9,000 lakes and 117,000 miles of streams are at risk in States east of or bordering the Mississippi. And scientists are now discovering that the problem extends west to Colorado, California, and the State of Washington. Evidence suggests that this forest damage is linked to acid rain related pollutants.

New Jersey also has seen effects of acid rain and its related pollutants, in the Pine Barrens, the Lebanon State Forest, and Kittatinny Mountains.

New Jersey faces a related problem with ozone nonattainment. The State is unlikely to meet the 1987 Federal deadline for ozone reduction.

One part of the solution to the acid rain problem is control technologies. Several companies in my State develop and sell control equipment to New Jersey's utilities and nationally. Today's testimony should give us a sense of where the Nation is with control technologies: Which are available, which are being used right now, which will be on line in the near future.

Mr. Chairman, again I applaud your commitment to this issue. And I welcome our witnesses here today.

Senator MITCHELL. I will now call the first panel of witnesses, which include Dr. Michael High, and Dr. Gene Mannella.

Good morning, gentlemen, and welcome. We look forward to your testimony. Your written statements will be inserted in full in the record and we ask you to provide oral summaries of them within five minutes. When this orange light comes on it means you have one minute left, and when the red light comes on it means your time is up. We do try to enforce it, at least for all those other than the Majority Leader.

We will begin with Dr. High.

STATEMENT OF DR. MICHAEL D. HIGH, DIRECTOR, DIVISION OF ENERGY DEMONSTRATION AND TECHNOLOGY, TENNESSEE VALLEY AUTHORITY

Dr. HIGH. Thank you, Mr. Chairman. It is a pleasure to be here this morning, when the red light comes on I will stop.

Senator MITCHELL. You can finish the sentence you are in.

Dr. HIGH. I am Michael D. High, Director, Division of Energy Demonstration and Technology for the Tennessee Valley Authority. In that role I conduct the research and development for the TVA power system.

As the committee knows, we are one of the largest coal-burning utilities in the U.S. and we have an active interest in clean coal technologies. It is really from that perspective that TVA has pioneered much of the work in clean coal technologies, and I think that makes us uniquely qualified to submit the following statement regarding these technologies.

We appreciate Congress' recognition of the importance of events in a wide-variety of clean coal technologies, which can prove to be cost effective in meeting clean air standards as they now exist or maybe modified in the future. Even with a healthy nuclear industry the United States will continue to depend heavily on coal-burning facilities to meet future electricity needs.

For the near term, that is from 1987 to the year 2000, the direction of the Federal clean coal technology program, we think, must address three significant related issues: plant age or retrofits; degree of commercialization or availability; and the efficiency of the pollution control devices themselves. Each of these issues bear on whether a particular technology will prove to be cost-effective and whether it will truly be useful in an effort to reduce power plant emissions.

TVA burned 30 million tons in 1986 and we forecast burns in that neighborhood from now to the year 2007 timeframe. This coal fuels a fossil system of the coal capacity of some 17,000 megawatts. Of that capacity, roughly 40 percent or 6,700 megawatts will be 40 years old or older in the 1990s. This represents 42 or 50 units that are 150 to 500 megawatts. Obviously, our existing fossil fuel system has aged, and yet the demands for electricity are such that we must continue to use it.

On a national level, we believe a similar situation exists. There are probably 200,000 megawatts or two-thirds of the coal-fired capacity in the eastern U.S., which have potential to undergo some form of life extension or repowering well past the 1990s and continue to meet demands in the year 2000. Consequently, it is clear that the electric utilities will continue to burn much of the coal used in the U.S., and burn that in plants that now exist.

It is imperative then that, if acid rain legislation is passed, the electric utility industry possess a menu of control technologies that are reliable and cost-effective for removing SO_2 and nitrogen oxides and takes into account the need to operate on older units. The need for this menu is apparent when you consider that retrofitting an existing plant is very site and plant specific. Some of the key parameters, for example, in that retrofit application are the boiler aging configuration, plant layouts and locations, what present emission controls exist, available coal supply, obviously, is important and additionally disposal sites for waste products are produced by most clean coal technologies.

The unfortunate fact is that the existing plants simply cannot accommodate some types of control technologies and to mandate the use of particular technology could mean that a badly needed plant may be shut down.

The general guidelines for the clean coal technology projects set forth in Senate Report 99-82, clearly recognized the necessity for demonstrating commercial feasibility. Of the nine initial projects selected by DOE's Clean Coal technology program, three projects would demonstrate near-term retrofit technologies for the electric utility industry. Those are the limestone injection multistage burner; induct injection process; advanced, air-cooled, cyclone combustor; and a combined gas-reburning sorbent-injection process.

Another major factor in the selection of a clean coal technology is, of course, its ability to comply with environmental regulations. The selected projects, which are designed to demonstrate new applications, such as pressurized fluidized bed combustion, coal liquification, and integrated coal gasification combined cycle, obviously, will be able to meet the new source performance standards, which require 90 percent removal in compliance 1.2 pound standard on SO_2.

However, all of the selected candidates have, for SO_2 removal, potential somewhere in the neighborhood of 50 to 60 percent, while the sulfur dioxide removal exceeding 70 percent would be required. It is in part because of these limitations that TVA has concentrated our research efforts and central technologies such as a lime spray dryer and a fluidized bed combustion programs.

Retrofit technologies for nitrogen oxide emission reductions are under various stages of development. Pulverized coal boilers can be retrofitted in most cases with conventional nitrogen oxide burners to reduce emissions 30 to 40 percent. New advanced burners could improve this figure to 60 percent. However, no burner technology is now available or even projected in the near future for nitrogen oxide control on cyclone boilers.

Selective catalytic-reduction technology is widely used in Japan and Germany on low-sulfur oil and coal. However this technology in a cost per ton of NO_x removed is exorbitantly high for comparable technologies in this country.

In light of the importance of retrofittability and the significant difference among coal technologies, it is unfortunate that the primary focus of the 1986 clean coal technology solicitation was not on retrofit applications with emphasis on coal-fired systems.

We highly recommend that the clean coal technology program reevaluate its selection process, emphasis moderate to high efficiency, low cost retrofits systems. If this direction is followed in the second round of solicitations the results achieved by the program should adequately address the basic need of retrofit for electric utilities.

In summary, we believe the clean coal technology must be developed, if public demand for electricity is to be met in an environmentally sound manner. However, an appropriate mix of near and long-term technology should be funded consistent with requirements of future legislation.

Thank you.

Senator MITCHELL. Thank you, Dr. High.

Dr. Mannella, before we ask you for your comments, I note the presence of Senator Baucus.

Senator, do you have any opening statement.

Senator BAUCUS. Not at this time, Mr. Chairman, thank you.

Senator MITCHELL. Thank you.

Dr. Mannella, would you proceed then.

STATEMENT OF DR. GENE MANNELLA, DIRECTOR WASHINGTON OFFICE, ELECTRIC POWER RESEARCH INSTITUTE

Dr. MANNELLA. Thank you, Mr. Chairman and members of the committee.

I am Gene Mannella, Director of the EPRI Washington office. I am pleased to be here this morning to present testimony prepared by Kurt Yeagar, EPRI Vice President and Director of the Coal Combustion Systems Division. Mr. Yeager, one of the preeminent clean coal experts in the United States, was looking forward to being here in person, only an extremely important meeting of our Research Advisory Committee compelled him to forego this opportunity.

Mr. Chairman, while EPRI has presented testimony on all aspects of our electric power and research and development program many times to both Houses of Congress I believe that we have not appeared before this committee for several years. Let me take a brief moment then, to reacquaint the members of our history and mission.

EPRI was established by the electric utility industry in 1972 to conduct a broad cooperative R&D program for the industry and its rate payers. We are a membership organization with dues primarily a function of electricity sales.

These voluntary contributions come from industrial-owned, government-owned and cooperatively-owned electric utilities. Our membership currently represents about two-thirds of the generating capacity in the United States and our annual budget is in excess of $300 million.

EPRI has been aggressively involved in clean coal programs for over 10 years and it has invested $700 million to date. Over one-third of our planned budget for the next five years will be committed to clean coal technologies because we believe that these technologies will show that coal utilization and environmental protection are mutually compatible.

Our program is driven by the awareness that today a large conventional fossil-fired power plant would cost about $1.5 billion, 30 percent of this expense attributable to environmental control. Without improved efficiency from new technology, large fossil generating plants may be economically driven out of the marketplace in many areas, resulting in loss of economic activity and decreased security of supply.

Our clean coal program has concentrated on technologies that offer both emissions and cost reduction concurrently. At some point in a not too distant future demand for electric power will outpace available generating capacity and other supply sources such as PURPA facilities. EPRI supports a balanced strategy to address this national issue, involving continued energy conservation, improved end-use technology, greater productivity from existing capacity and more efficient new capacity. All of these activities are contained in our overall EPRI program.

Specifically with regard to coal-fired power plants, our program pursues technologies optimized for retrofitting existing plants as well as those more suited for repowering, and new capacity. Retrofit technologies range from improved physical coal cleaning to combustion modification, sorbent-injection, partial and dry scrubbing, and low-NO_x combustion. New capacity and repowering embraces fluidized combustion, both in atmospheric and pressurized configuration, as well as integrated gasification combined cycle systems.

All of these technologies must be proven in utility-operating environments for them to successfully go forward, which is an expensive undertaking. However, we feel that they merit serious commitment, because in the long-run they would be more cost effective as well as environmentally responsive. Details on each of these technologies are contained in the appendix of our testimony.

Why so many technologies, one may ask? Why can't we pick just one and demonstrate it? As Dr. High just mentioned the utility industry is diverse, with over 1,000 fossil plants each representing a somewhat different configuration and using coal of different characteristics. To provide utility decision-makers with suitable technical options, we need an array of technical solutions, particularly where retrofitting existing plants is concerned. In our ten years of involvement in clean coal technology, we have winnowed out those that cannot effectively compete. The technologies discussed in the appendix of our testimony have withstood competitive analysis and are the most promising that we have investigated.

Mr. Chairman, the answers to the specific questions in your letter of invitation are contained in Mr. Yeager's written statement and its attachment. I apologize for the fact that they are not formatted exactly as asked, but we were working on a relatively short timeframe from when the letter was received and the material was due up here to the committee.

I would like to briefly address Question 5 directly, however. EPRI, including its advisory structure of over 500 utility experts and member utilities hosting ongoing demonstrations, probably has a better overall feel for clean coal technology and its prospects than any other single organization. We remain convinced that clean coal technologies combining environmental protection with greater process efficiencies are an ideal answer to many of our concerns, and we have committed a significant portion of our resources to assist in their development and demonstration, leading to their subsequent commercialization.

Indeed, the utility industry has already demonstrated leadership in funding the major portion of the development of these technologies to date. This is prima facie evidence of their good faith and commitment. If the recommendations in our statement with regard to the necessary further demonstrations are followed, our extensive involvement with the industry leads us to believe that clean coal technologies will indeed be implemented directly following.

This concludes my remarks, Mr. Chairman. I would be happy to answer any questions that you or the other members may have.

Senator MITCHELL. Thank you very much, Dr. Mannella.

Before we proceed to questioning, I note the presence of Senator Chafee and Senator Warner and ask whether either of you gentlemen have an opening statement that you would care to make.

Senator WARNER. I have a brief one, Mr. Chairman, that I will ask to be submitted for the record.

Senator MITCHELL. It will be done.

[Senator Warner's statement follows:]

OPENING STATEMENT OF HON. JOHN W. WARNER, U.S. SENATOR FROM THE STATE OF VIRGINIA

Mr. Chairman, I want to thank you for this opportunity to participate in the hearing today to discuss the progress of the Clean Coal Technology Program and its contribution to the acid rain debate.

Although I am not a member of this Subcommittee, I have had a keen interest in this issue since serving on the Energy and Natural Resources Committee.

In 1984, I was pleased to join Majority Leader Byrd and other Senators in securing $400 million over three years to demonstrate advanced technologies to burn coal more cleanly.

Last year, Majority Leader Byrd, Senator Ford, myself and others were successful in directing the Department of Energy to solicit notices of interest for technologies to retrofit operating power plants.

Today, we are moving forward with the Clean Coal Technology Program with significant financial support from the Federal government, State governments and the private sector.

This morning, we will hear from experts in the private sector who will testify on the performance, prospects for commercial application and documented emission reductions from these technologies.

My continuing conern has been that the Congress has discussed at length the complex phenomena of acid rain, without giving proper attention to the Clean Coal Technology Program.

If the Congress chooses to enact specific acid rain control legislation, I believe we must fully acknowledge its potential impact on the success of the Clean Coal Technology program.

We must remember that the principal reason for establishing the Program was to increase the use of coal in an environmentally acceptable manner. It was not created to address the acid rain issue.

However, the Clean Coal Technology Program and the acid rain issue are not mutually exclusive.

If Congress enacts specific acid rain control legislation, it will have a lasting effect on the success or failure on the market acceptance of Clean Coal technologies.

On the other hand, the commercialization of these new technologies will make significant contributions to reducing emissions from coal-fired power plants.

I know the Committee will benefit from the opinions offered today on the status of the various clean coal technologies and the promise they hold for the future of our energy security.

Coal is our most abundant energy resource. For our nation's energy security and independence, we must continue to recognize coal as a stable, dependable energy source on which we rely, not an energy source that we discourage.

Increased coal use and a clean environment are compatible and essential goals which we can accomplish through the Clean Coal Technology Program.

We must give the program time to prove itself.

Senator MITCHELL. Thank you very much. We will now proceed to questions and we will limit the first round to five minutes in order of appearance by the Senators.

Dr. Mannella, in the written statement by Mr. Yeager, he says that,

> A requirement to apply current flue gas scrubbing technology to existing units would impose an additional cost of nearly $300 per kilowatt hour.

That is in the middle of page 5 of the statement which you are presenting.

In October of 1986, your organization EPRI published a document for the industry entitled "Economic Evaluation of Flue Gas Desulfurization Systems." In that document, in doing your research for the industry, you estimated that the capital costs of scrubbers are $129 per kilowatt hour.

How do you account for the discrepancy between the figure given in your publication for the industry and your testimony for this committee today?

Dr. MANNELLA. Mr. Chairman, I am sorry. I am going to have to supply that answer for the record. I am not familiar with that report personally, and I am going to have to back and look at it and see what basis it was computed on and what basis Mr. Yeager's figure was computed on.

[The information requested was not supplied in time for publication.]

Senator MITCHELL. Thank you I would appreciate it if you would do that. As you know, Doctor, you were here during Senator Byrd's testimony, he quoted at some length from a statement by Mr. Yeager before the Senate Energy Committee last year.

It is at page 4 and 5 of Senator Byrd's statement, and he said:

> Mr. Yeager summarized the case against an acid rain control program that would retrofit flue gas scrubbers on existing high-sulfur coal-fired technology.

Mr. Yeager then said that, if the $200 billion necessary to implement the scrubber retrofit strategy—and then he goes on to make a comment. What legislation would require that?

Dr. MANNELLA. I am not sure that he was specifically referring to any legislation. I think he was just making an observation.

Senator MITCHELL. Right. That is precisely my point. What Mr. Yeager did was to attack a solution to the problem, but a solution which no one has suggested.

In other words, he has taken a hypothetical solution, which none of the proponents of legislation have required and has set that up as a straw man to attack and I think that should be made clear.

This is a hypothetical solution, which none of the bills now before the Congress would specifically require, and that ought to be made clear in evaluating his testimony.

Dr. High, I wanted to ask you; you commented on retrofitting in your statement. Senator Byrd also commented on retrofitting. I want to make it clear that there is no implication that retrofitting would occur solely as a result of the enactment of acid rain legislation.

Am I correct in my understanding that retrofitting now occurs because the cost of new plants is so high, and that utilities are extending the life of existing plants for economic reasons not due to any acid rain control program? Indeed, I am advised that the EPA used to assume a 30-year useful life for plants, and now it assumes a 60-year life. Am I correct in my understanding as just stated?

Dr. HIGH. Basically you are correct. The life extension programs that will be carried out are primarily for economic reasons. That is the lowest cost way for us to meet supply.

Senator MITCHELL. Any implication that may be created by statements regarding retrofitting as though retrofitting would occur only as a result of acid rain control legislation, do not portray the full context, which is that it is now occurring in the absence of any control legislation, for reasons other than that and would presumably continue to occur for the same reasons in the future?

Dr. HIGH. I don't think that is entirely correct, if I understand your comment, Senator. As we extend the life of the units, we normally don't retrofit a control technology on those because we normally don't replace a major part of the power plant, so they don't fall under a new source performance standard. What you say is partially correct, but not entirely.

Senator MITCHELL. I understand what you are saying and I accept that as a correct statement.

There will undoubtedly be some additions to the retrofitting process, if acid rain control legislation is enacted. I think that is clear. I merely wanted to point out that it is occurring now, at least in some respects, and for reasons other than acid rain control legislation.

Thank you very much gentlemen. I will now proceed to Senator Stafford.

Senator STAFFORD. Thank you very much, Mr. Chairman. I was going to ask unanimous consent that members who have questions that occur to them as a result of the written statements be allowed to submit those questions in writing?

Senator MITCHELL. Without objection that will be done.

Senator STAFFORD. Mr. Chairman, let me address my first question to Dr. High.

TVA is currently in compliance with the current clean air requirements as far as your steam-powered, coal-fired plants are concerned, is it not?

Dr. HIGH. Yes.

Senator STAFFORD. How was that accomplished?

Dr. HIGH. Through a number of methods. We have installed wet limestone scrubbers on about 2400 megawatts. We have switched to low-sulfur coal on some units, and those kinds of measures. So it was a flexibility that was allowed to TVA to meet those requirements.

Senator STAFFORD. You have used low-sulfur coal in some of your plants. Is that true?

Dr. HIGH. Yes, that is true.

Senator STAFFORD. You have several nuclear plants that are currently out of production. Hypothetically, if they came on production, would that reduce reliance of TVA on coal-fired plants?

Dr. HIGH. That is correct. For the near-term, in the next seven to ten years, that is correct. We would back down the production out of our fossil units.

Senator **Stafford**. Could you give us any percent as to how much shut down would occur on the fossil-fired units?

Dr. **High**. Our loads have been fairly steady recently and so there would be almost a one-to-one correspondence and currently we have about 5,000 megawatts of nuclear power that is shut down, so that would be a rough comparison to the amount of fossil we would decrease.

Senator **Stafford**. Could you tell the committee when the AFBDC plant in Shawnee might come on-line?

Dr. **High**. We plan to have steam to turbine on that plant in June, 1988. Next year.

Senator **Stafford**. That is a 140 megawatt plant?

Dr. **High**. 160.

Senator **Stafford**. Thank you very much.

Dr. Mannella, on the opening page of your statement, you discussed current environmental control capabilities and the necessity for improvement. But then you say "these controls in their current form also have a major impact on plant efficiency and reliability."

Can you expand on what you meant by that sentence?

Dr. **Mannella**. I believe what we meant to convey there, is that in meeting the new source performance standards today with the technology that is available, that one would use techniques which result in a lower output or lower efficiency than would otherwise be the case.

One of the reasons why we are pursuing the new clean coal technologies, as I mentioned earlier, is that we are looking for both process efficiencies as well as environmental control.

Senator **Stafford**. Does the AFBDC process look promising to you?

Dr. **Mannella**. It certainly does, and it is one of the projects that we have made a major financial commitment to.

Senator **Stafford**. Thank you, Mr. Chairman.

Senator **Mitchell**. Thank you, Senator Stafford.

Senator Baucus?

Senator **Baucus**. Thank you, Mr. Chairman.

Gentlemen, when the Clean Air Act was passed, in 1977, it was expected that by the early 1980s many of the plants would be retired and new plants would be built.

In listening to you, you seem to be saying that that didn't happen because of economic reasons, and the economic reasons are broken down to several: One, new plants had to meet higher environmental air control standards, that is more expensive; and second, there are other economic factors that make it less economic to build new plants compared with retrofitting.

My question is, we are here, today, 1987, and we are hearing wait for the new technologies, give us new plants, that is the same point we heard back 10 years ago, 1977, and as we know, new plants were not built. Basically, as we said they were retrofitted contrary to expectations back in 1977.

My question is, what is different? What is different today from 1977?

Today you say wait for new plants, wait for new technology to be incorporated in new plants. Why should we expect the new technologies to be developed and new plants built? Why should we expect anything to be different in the next 10 years as compared to what has happened in the last ten years?

Dr. MANNELLA. I can think of several reasons, Senator Baucus. One is in 1977 the technologies that we are talking about were barely in the initial phases of development and since that time, as I mentioned in my statement, we have invested about $700 million and the utility industry has probably invested twice that much in terms of other costs that have not flowed through EPRI.

With regard to the suggestion of the commitments that were made in 1977, about the plants, I wasn't part of the Clean Air debate, but I was part of the national energy debate at that time and our view of the future then was a lot different than what turned out to be. We were all looking at and projecting electricity growth rates of 6.5 or 7 percent. We were talking about $2 a gallon gasoline and what have you. Obviously, many of the things that we all nationally thought were going to happen and we prepared for did not occur and there is no way to guarantee what the situation will be in 1997.

Senator BAUCUS. There is no way to guarantee, but you said that technology now is different than it was then.

Dr. MANNELLA. It is much farther advanced.

Senator BAUCUS. If it is much farther advanced, then why can't we proceed with present technology or nearly present technology? You said it is much farther advanced, if we have much farther advanced technology why shouldn't we proceed now and not "wait" for some future still newer technology?

Dr. MANNELLA. Speaking strictly to the technology from the EPRI standpoint, as we outlined in the appendix to our statement, we give specific recommendations for commercial demonstration requirements, and each technology that we feel would be necessary to bring it to the marketplace. Most of this technology is not commercially available today, it is just entering the demonstration phase.

Senator BAUCUS. Don't you think though that legislation helps drive new technology?

Dr. MANNELLA. Undoubtedly it does.

Senator BAUCUS. Shouldn't the Congress encourage that newer technology by helping to drive it?

Dr. MANNELLA. I think they have.

Senator BAUCUS. Don't you think we should tighten the screws a little bit more?

Dr. MANNELLA. No, sir.

Senator BAUCUS. Why not? If it has worked in the past, if tightened screws help, someone once said, "if it ain't broke, don't fix it." Why not continue to tighten the screws a little more?

Dr. MANNELLA. I think that the answer has to come in several parts. First of all, the development of the technology has been aggressively pursued by the industry. The motivation, I think, is to prepare themselves and have suitable options for whatever the future may hold, in terms of either projected growth rates, or legislation, or what have you. We are on a proper course and I think that the investments that we have made will pay off.

Senator BAUCUS. I feel that it is human nature to procrastinate. Certainly this body here, the United States Congress, is the best evidence of that. We wait until the last moment before we finally pass budget legislation, appropriations bills, what ever. It is human nature. I think that at the coal industry they are human beings. It is human nature for the coal industry to wait, to procrastinate.

I, therefore, think that it makes more sense for us, as a body, to try to get ahead of the game a little bit and not wait for the last moment and, therefore, do what we can to constructively and responsively try to encourage, a little more quickly, the development of technology. I think that often putting technology in place is the best way to learn, as to what works and what doesn't work.

The more we wait for the perfect solution the more we are never going to have a solution. There should be, learn by experimenting. It would be practical and pragmatic about this, and I think that it would be better served in the long-run, if we tend to encourage all of us as a country to develop these technologies even more quickly than we have in the past, because if we wait for the ultimate solution we are never going to have it. Thank you.

Senator **MITCHELL**. Thank you for your statement, Senator Baucus.

Senator Chafee?

Senator **CHAFEE**. Thank you, Mr. Chairman.

Gentlemen, I would like to ask you the following question. Throughout the testimony, certainly your testimony, Mr. Mannella, if I understand it and certainly Senator Byrd's statement, stresses the tremendous cost of going into a new plant.

The thrust seems to be: How are we going to retrofit; which way are we going to proceed in this legislative drive; what type of system you use to retrofit? But the whole thrust seems to be, above all, whatever we must do, we must not build any new plants, because that is very, very expensive.

How long, this was touched on by Senator Baucus, are we going to keep this up? Senator Byrd touched on the word "competitiveness" in his testimony. How do we remain competitive by making sure that everything we do is to hang on to old plants?

Why don't we take the plunge and get some new plants. Sure, it is going to be expensive, but presumably, if we have new plants, they are more efficient and thus we, at the same time, can deal with this problem, that on this committee we think is a crisis, despite what Senator Byrd and others have suggested that there really is no crisis out there.

It is advancing from the assumption that we believe in this committee, that something should be done about acid rain. Why not proceed with some new plants?

Dr. **MANNELLA**. We would just like to note that since 1973, the consumption of coal by the utility industry has increased 70 percent, while the sulfur emissions have been reduced by 26 percent. What we see is a long-term, gradual decline in SO_2 emissions. We don't see any environmental precipice that we are about to go over and plunge into the wild blue yonder.

With regard to the plants, you must keep in mind, what you are talking about is the expenditure of very significant sums of money, in some instances equaling the book value of the utility, which somebody has to pay for, with the public utility commission holding hearings as to the prudency or the need for that new capacitiy. It is a very complicated issue.

Senator CHAFEE. That is not really an answer; that it is complicated and therefore let's not do it.

I presume that there is a limit to the use of these plants, and you are proud that you have extended the life of them for so many years, but you have got to build a new one sometime, I presume.

Dr. MANNELLA. I didn't mean to suggest that we were saying, "let's not do it." What our whole philosophy has been, as we tried to describe today and as we have described in other testimony, is that we believe that these technologies can provide both process efficiencies, that is lower cost of electricity generation, and environmental responsiveness, and that that is the way to go. As new plants are required, and they are fossil-fueled, these new technologies should be available.

Senator CHAFEE. As I get the testimony, you are not building new plants.

Dr. MANNELLA. That is because there is not the demand for them.

Senator STAFFORD. Would the Senator yield for one question.

Senator CHAFEE. Yes.

Senator STAFFORD. Am I correct in assuming that what you don't want to do in the industry is to retrofit plants with scrubber technology that were built before 1977? You don't want to build new plants with that kind of technology, because you think it may be outmoded by some of the developments that are coming along; would that be a fair statement?

Dr. MANNELLA. I don't think so. The decision for new plants is the function of the demand that the utility sees for electric power. They will satisfy that demand either with new construction or purchase of power or whatever is most economical for their ratepayers. The question relating to the existing plants to retrofitting in part relates to the development of retrofittable technologies.

I would like to make one important distinction. The technology that relates to new plants, offers both process improvement and environmental responsiveness. The processes relating to retrofitting existing plants, only offers opportunities to reduce the cost of compliance. There is no way that you can get additional efficiency out of retrofitting those old plants.

Senator CHAFEE. Let me ask you; when you build a new plant, don't you get efficiencies?

Forget the new source performance standards, the environmental aspects, does nothing come from a new plant as far as greater efficiency goes?

The only reward, in a new plant, would be an ability to adhere to environmental standards to a greater degree. There are no greater efficiencies that come from it. I find that hard to believe.

Dr. HIGH. I am not sure that I understand your question.

Senator CHAFEE. I will make it simpler.

When you build a new coal-fired generating plant, don't you receive greater efficiency from that plant in a multitude of ways as opposed to an existing plant? Isn't there something in it for you?

Mr. HIGH. There is not enough efficiencies gained in a new plant to offset the cost that you have to add to capital. New plant capacity here is really a load demand function, and not an environmental question, if I may address it that way.

We certainly don't believe we are making decisions to run our old plants as an environmental issue. Those are strictly load demand, and the cheapest way for us to meet that demand. But you cannot build a new plant today, in today's environment, and I don't mean air environment, but financial environment, at a cheaper cost, despite efficiency gains, than you can making a capital to extend the life of your old plant. Those two are nowhere near the same in a cost to the utility, or the ratepayers, in comparison.

You really don't want to make a capital investment in a new plant unless your demand for electricity forces you to do that, as long as you can meet that demand with what you have, or a cheaper capital investment, and that is a life extension. I think that this is pretty clear to most of us. I don't think that we mean to suggest that life extension is a way to circumvent the Clean Air Act.

Senator CHAFEE. It is a fringe benefit, though, isn't it, if you go to a new plant, you have to meet the new source performance?

Mr. HIGH. I don't believe that we set out, though, to reap that fringe benefit. I don't think that this was a deliberate plan.

What concerns me, I think, Senator, and you talk about technologies being available, we put the first scrubbers on plants. In fact, we had the first large scale one in operation.

We began in the middle 1970s to develop technologies that we saw were going to be better, and it takes 10 to 15 years to get those technologies. We believe that in the next 5 years those clean coal technology menus, that give you the flexibility that you need, not only new plants but retrofits, will be there.

We would ask that any legislation that is passed give us the flexibility to meet those regulations in the least cost way that we can for our ratepayers.

Senator CHAFEE. Thank you, Mr. Chairman.

Senator MITCHELL. Thank you.

Senator WARNER. Thank you, Mr. Chairman.

Just a quick follow up. Can some of the retrofit technologies be easily employed in life extension programs?

Mr. HIGH. Some of the retrofit technologies that have moderate removal rates can be fairly easily adapted, and that is reflected, of course, in the cost per ton of pollutant removed when you look at the cost figures. Induct injection, for example, is not a major modification. Nitric oxide removal by burner modification may be fairly expensive because you will have to take units off-line to do that. The answer is kind of multi-faceted.

Senator WARNER. It is a mix, then?

Mr. MANNELLA. Yes.

Senator WARNER. We have heard strong objections from supporters of the clean coal program, both in the Federal Government and in industry, that the schedules for emission reductions provided in all the proposed acid rain control bills would restrict the investment in research and eventual market use of clean coal technology.

Can you provide the subcommittee with an idea of the time involved in establishing and testing the technologies on a pilot plant scale?

Mr. HIGH. You are asking about how long does it take to get a technology in place?

Senator WARNER. Yes.

Mr. HIGH. I can give you a specific example. We built a 20-megawatt fluid bed pilot plant. We started construction in 1979, and we started operation in 1982. We began construction of the demonstration plant last year, and we expect to have that on line in 1988. It is nine years, that is fairly fast-track, as a matter of fact, and it is that kind of timeframe for a major technology that you have to allow, and there are several of those out there. It is a long time to do.

Senator WARNER. Thank you, Mr. Chairman.

Senator MITCHELL. Thank you, Senator Warner.

I would like to ask the two of you one further question. It is my belief that there are existing technologies that can be used to retrofit plants to meet acid rain controls, should they be enacted, and that further technologies will be developed in the near future. I take your statements to support that.

Dr. High, you said, on page 5, "these technologies," you were referring to fluidized bed and dry-lime scrubbers, "should be available for wide-scale deployment in the early to mid-1990s."

Dr. Mannella, you said that "retrofit can become particularly valuable in the event emission controls on existing high sulfur plants is required. The potential for 50 to 70 percent reduction is attractive under these circumstances."

I recognize that you are not in favor of controls, and witnesses in the next panel will make similar, indeed stronger statements. Based on your statements and those of others, do you agree that there are now available retrofit technologies, and that there will be more available in the near future that could effectively control emissions of the precursors of acid rain?

Mr. HIGH. Let me attempt to answer that. Yes, there are technologies. We obviously have wet limestone scrubbing technologies on some of our plants now, and those technologies will meet the new source performance standards. Those technologies, however, are not, in our judgment, the best thing to do.

Given the timeframe we are in on developing the other technologies, and in particular if the clean coal technology moves forward, we think that the new technologies will be a much better way to do that. But those technologies are not yet available.

I think I indicated in my testimony that by the middle of the 1990s, a menu of clean coal technologies will be available.

Senator MITCHELL. The legislation that is pending would require action within 10 years, would it not?

Mr. HIGH. Some of the legislation phase in a little more rapidly, and there is a mismatch in those kinds of phases.

Mr. MANNELLA. I agree with Dr. High's comments. I would like to draw your attention to Figure 6 in my testimony, which shows that there are two commercially available technologies. One that is characterized by low removal, that is on the left, that is A, which is essentially coal cleaning, and one which is characterized by very high rates of sulfur removal, and that is the area A on the right, which also has a very high cost.

As we discuss in our testimony, and we mean to show here, we think that the technologies in B and C, which we hope to see in the coming decade, offer comparable removal rates at lower cost.

Senator MITCHELL. I will just conclude with one comment. Dr. Mannella, you said that we are not facing any environmental precipice, and others have made the same statement. I would ask you, if you would, get the transcript of the testimony before this committee of a few weeks ago in which four physicians testified—the President of the American Pediatric Association, the President of the American Health Association, and two other very eminent physicians—about the adverse effects on the health of American children by acid deposition.

I would like to have you show me personally that you will read that testimony, and then you write me a letter to tell me whether you still think that we don't face any kind of environmental precipice.

Mr. MANNELLA. I will be happy to do that, Mr. Chairman, I promise you I will read it. I would like to say at this point in time that I did not suggest that we had no problems related to environmental control or environmental problems. What I said was that we did not feel that we were going over a precipice.

Senator MITCHELL. I suppose what is or what is not a precipice is like many things in the eyes of the beholder. After you read that testimony about the health effects on American children, you might not regard it as a precipice, but the doctors who testified certainly did, those who see children every day, and I have to share their views.

Thank you, gentlemen, very much for your testimony

Senator BAUCUS. Mr. Chairman, I just have one question.

Senator MITCHELL. Senator Stafford next, and then Senator Baucus.

Senator STAFFORD. I will be very brief, Mr. Chairman. Could you comment, either one of you on the panel, on the question of is it expensive to switch from high sulfur to low sulfur coal on existing plants?

Is that an expensive switch, and I am talking only about the technology, and not about other questions like transportation costs, and so on?

Dr. HIGH. The question is, is it expensive to switch from high sulfur to low sulfur as a compliance strategy?

Senator STAFFORD. Yes.

Dr. HIGH. If you exclude transportation, the answer is no, because the majority of the expense, at least for our system, is transportation. Most of our plants are located in medium to high sulfur coal fields, so it is expensive for TVA. I can only answer for TVA in that respect.

Senator STAFFORD. I just wanted to know about the cost of the technology. I recognize the fact that the transportation costs, locations, and sitings play a major part in this.

Thank you.

Senator MITCHELL. Senator Baucus.

Senator BAUCUS. Thank you, Mr. Chairman, I will be brief, too. I might say, gentlemen, I was at the hearing when the pediatricians testified about the adverse health effects of the precursors of acid rain, that is SO_2, NO_X, and so forth, and I was frankly stunned by their testimony. It was a whole new revelation to me personally. Maybe others in the country knew all about this, but I am just telling you that personally it was quite a revelation. I follow up on the request of the chairman that you get that testimony and read it. I think you too will be quite disturbed by those physicians' findings.

Secondly, I would like to hear your most compelling arguments as to why, in fact, new coal technologies will be commercially available by, say, early to mid-1990s. What is the most compelling argument you have?

Other than just words, other than assurances. and other than just promises, what is the most compelling argument you have?

Dr. HIGH. I think the most compelling argument that you can put forward is the commitment that has been made, the several commitments, by the utility industry and many others in this industry, to do the research that is necessary to get in there and show the progress that we have made to date. We have moved the coal gasification technology forward as evidenced by the Cool Water.

Senator BAUCUS. How much more has been spent in research in dollar terms or percentage of sales, or any way that you want to say it?

Dr. HIGH. I can only speak for TVA in that respect but we spend about 1.2 percent of gross revenues, which are in the neighborhood of $5 billion.

Senator BAUCUS. What percent of your R&D?

Dr. HIGH. That is the percentage of R&D. How much of our R&D is spent on clean coal technologies?

Senator BAUCUS. Correct.

Dr. HIGH. About 50 percent.

Senator BAUCUS. You say that for your total R&D, you spend 1.2 percent, so 0.6 percent of your sales is R&D for clean coal.

Dr. HIGH. That is correct.

Senator BAUCUS. Is that 0.6 percent of gross sales for each year, or is that increased?

I would like to know what percent of gross sales has been spent on clean coal technology for each of the last 10 years?

Dr. HIGH. I think that the figure that I gave you is pretty representative of TVA since 1979. I don't have any history beyond that, because that is when I joined the organization.

Senator BAUCUS. Since 1979, it is basically 0.6 percent.

Dr. HIGH. Yes.

Senator BAUCUS. How does that compare with other companies in each of the last 10 years, I want to know what the trend line is here?

Dr. HIGH. I will defer that question.

Dr. MANNELLA. I can recall those figures. As I mentioned, the industry through EPRI has spent about $700 million over the last 10 years, and has committed a third of its budget over the next 5 years, which would be, I believe, another $500 million.

Senator BAUCUS. I am talking about your R&D budget.

Dr. MANNELLA. That is our budget, R&D is essentially our business. About a third of our budget for the next 5 years will be going to clean coal technology.

Senator BAUCUS. Thank you.

Senator MITCHELL. Thank you.

Senator Warner, do you have any other questions?

Senator WARNER. Just one clarification. On the switch from high sulfur to low sulfur coal, putting aside transportation, I think we should make it eminently clear that there are associated costs with the conversion of that plant that are not inconsequential. Am I not correct about that?

Dr. HIGH. If you are talking about an eastern bituminous coal, the conversion is not significant. If you are talking about a sub-bituminous, western sub-bituminous coal, then the conversion to that type of coal is significant in terms of the derating.

Senator WARNER. Thank you very much.

Senator MITCHELL. Thank you, Senator.

Thank you very much, gentlemen.

We will get the next panel seated, and then we will ask Senator Pressler for his statement. This panel consists of Dr. Flynt Kennedy, Mr. James R. Tacheny, Dr. Lawrence T. Papay, Mr. Paul Lahaye, and Dr. F. P. Boer.

Gentlemen, welcome. Before we begin your testimony, I will note the presence of Senator Pressler.

Senator Pressler, do you have an opening statement that you would care to make?

OPENING STATEMENT OF HON. LARRY PRESSLER, U.S. SENATOR FROM THE STATE OF SOUTH DAKOTA

Senator PRESSLER. Yes, Mr. Chairman, I do, but I shall place it in the record.

I do want to thank you for scheduling this hearing on emerging technologies for controlling sulfur dioxide and nitrogen oxide emissions. It is critical that the committee include discussion of new technologies when acid rain or any pollution control legislation is considered.

I recently had a meeting with John Harrington on this subject. I have a statement expressing interest in the development of methanol and ethanol as fuels for automobiles and buses as one way to lessen part of the problem.

I shall submit the remainder of my statement into the record.

[Senator Pressler's, statement follows:]

OPENING STATEMENT OF HON. LARRY PRESSLER, U.S. SENATOR FROM THE STATE OF SOUTH DAKOTA

Mr. Chairman, I want first to thank you for scheduling this hearing on emerging technologies for controlling sulfur dioxide and nitrogen oxide emissions. It is critical that the committee include discussion of new technologies when acid rain or any pollution control legislation is considered.

Last week I met with Secretary of Energy John Herrington and one of the issues we discussed was the Energy Department's research on new technologies for using fuel more efficiently and to reduce pollution. Some of this work is very exciting. The development of these new technologies is not only important environmentally, but also in economic terms.

I have taken a special interest in the development of methanol and ethanol as fuels for automobiles and buses. For several years ethanol has been added to gasoline as an octane enhancer. Along with increasing the octane level, ethanol also provides environmental benefits by reducing nitrogen oxide emissions. Currently there are several demonstration projects in which methanol is being used on mass transit buses. The use of methanol substantially reduces nitrogen oxide emissions. With new advances and increased use of current technology, great strides can be made in reducing nitrogen oxide emissions from mobile sources and our dependence on foreign oil supplies.

When this committee or the Senate considers any legislation it is critical that new technological developments be taken into consideration. The development or implementation of new technologies in some cases may eliminate the need for regulations or provide industries with more cost effective means of meeting emission standards. It is also important that legislation not inhibit the development of new technologies. Our nation's economy has been built with innovative thinking and being on the cutting edge of technological development. We must encourage these creative initiatives.

Mr. Chairman, I look forward to hearing the witnesses' comments and learning more about current technological advances in controlling acid rain.

Senator MITCHELL. Thank you, Senator.

Welcome, gentlemen. We will begin with Dr. Kennedy. If you, gentlemen, were not present, I will restate the rules. Except for Senators and Cabinet Members, we ask all witnesses to limit their oral remarks to five minutes. Your written statements will be printed in the record for review by the Members of the Committee. This red light will tell you when the five minutes are up. Thank you very much.

STATEMENT OF DR. FLYNT KENNEDY, MANAGER, COAL RESEARCH DIVISION, CONSOLIDATION COAL COMPANY

Dr. KENNEDY. Good morning. I am Flynt Kennedy, General Manager of Coal Research and Development for Consolidation Coal Company, a Du Pont subsidiary.

Our Research Division, established in 1947, is staffed with 160 scientists, engineers, and support personnel in Pennsylvania and West Virginia, who are focused on providing technology to overcome economic or environmental barriers to the maximum use of coal. Our research budget is about $15 million per year. About two-thirds of our research effort, directly or indirectly, addresses environmental issues.

Consol has lengthy experience in SO_2 technology development. In the 1970s, Consol pioneered the CONOSOX process, an advanced process for the removal of SO_2 from utility boiler flue gas, which produced a saleable byproduct rather than a disposable waste.

Because of its chemical complexity, the CONOSOX process costs grew to the extent that further commercial development was discontinued. As a result, we recognized the need to develop a menu of SO_2 compliance technologies so that at least one cost effective open is available to each coal user.

In 1984, Consol conducted the first successful large-scale test of boiler limestone injection, which included limestone injected multistage burners, or LIMB as it is commonly called, with high sulfur coal. This 15 megawatt industrial boiler demonstration at Martinsville, Virginia, showed that injecting limestone into the furnace is an effective means of achieving partial SO_2 removal, about 50 percent, without impairing boiler performance.

Consol also tested a related process involving sorbent injection into the flue gas downstream of the boiler. Named the Coolside process, this technology proved capable of over 75 percent SO_2 removal at acceptable sorbent injection rates.

Although Boiler Limestone Injection and Coolside cannot achieve the 90 percent or greater SO_2 removals of commercial flue gas desulfurization units, FGDs, better known as scrubbers, they are low in capital cost, require less space for installation, and can be installed in a relatively short time. Therefore, they are attractive entrees on our menu for lower capital cost retrofit applications at older utility stations which might require partial SO_2 reduction for compliance.

During the Martinsville tests, Consol also pioneered the use of flue gas humidification, which maximizes SO_2 capture, while minimizing the particulate emissions which result from sorbent injection. We have presented our results to utility, industrial, and government audiences, and we will dedicate patents to the public domain.

We have vigorously pursued opportunities for full-scale demonstration, and we will provide technical and financial resources to such demonstrations. As a result, humidification and the coolside process are included in an EPA sponsored demonstration of a boiler sorbent injection process. The demonstration will be conducted using 105 megawatt boiler at Ohio Edison's Edgewater Station, near Cleveland, and is scheduled for completion in 1989.

Cosponsors and participants include the State of Ohio, Ohio Edison Company, Consol, and the prime contractor, Babcock and Wilcox. Partial funding for this expanded, broad-based demonstration was provided by DOE under their cléan coal technology program, and it is one of the nine projects included in Phase I.

Bechtel, Dravo, General Electric, DOE, and EPA are also involved in process development of retrofit technologies for partial SO_2 control. As we evaluated these new technologies, we realized that well-designed, conventional, wet FGD technology currently in commercial use in this country, and advanced wet FGD processes, which are fully ready for commercial application, also have a prominent place on the menu.

Although higher in capital cost than emerging sorbent injection technologies, these wet FGD processes are lower in operating cost because of the more efficient use of the sorbent materials. This means that once an FGD unit is installed, power can be generated at the lowest incremental treating cost.

The units are reliable, as shown by recent experience gained in this country and abroad. Therefore, wet FGD can be a technology of choice even in retrofit situations for those larger base-loaded units for which the capital cost will be more than offset by lower operating costs.

We are working closely with utility customers to develop a demonstration project of advanced wet FGD technology as applied to high sulfur coal for the anticipated second solicitation of clean coal technology funds.

Other clean coal technologies, such as atmospheric and pressurized fluidized bed combustors and integrated gasification/combined-cycle power generation, are at commercial or near-commercial stages of development. These technologies produce power with low levels of sulfur oxide emissions by integrating sulfur control into the process itself. However, they will find greater application in new power generation, or in repowering of existing facilities to add incremental power generation capability, rather than in retrofitting strictly for environmental compliance.

In summary, we have a growing menu of technologies which, if commercialized, can meet the short-term and long- term environmental compliance needs of the electrical generating industry. No single technology will fulfill every need, so we must support the simultaneous advancement of a variety of processes, which includes the development of new technology, and optimization of existing technology.

Private industry is making a strong effort, on its own initiative and/or assisted by Federal funds, to develop the technology needed. The interests of the fuel producer, power generator, and energy consumer are best served by continuing to provide a variety of options to achieve the optimum balance between environmental needs and economic realities.

Senator MITCHELL. Thank you, Dr. Kennedy.

Senator Durenberger is here. Senator, we welcome you for an opening statement, and to introduce the next witness.

Senator DURENBERGER. Thank you very much, Mr. Chairman.

Let me say that it is a pleasure to introduce Jim Tacheny to you. I haven't seen him in a while, he has gotten a little older, and so have I.

We both come from Lake Wobegon, at least that is where we went to college. I just have to say that because Garrison Keelor, who came after us on this little college campus and made Lake Wobegon, is now going to Denmark, and some of you might forget that there was a Lake Wobegon.

Jim and I met at this very small college up in the middle of nowhere in Minnesota. He went on to become a very famous person, and I became a politician. I am just pleased to have the opportunity to have him here today.

When it comes to the issue of acid rain, and the technologies and the investment, there is not a public utility in America that is as responsible as the Northern States Power Company, not only because Minnesota has done some work in this area earlier than other places, but because, as a company, they are very sensitive to the environmental needs of their consumers as well.

I don't know what he is going to say, but he is a great guy, and I am glad that you invited him to testify.

STATEMENT OF JAMES R. TACHENY, VICE PRESIDENT, SYSTEM PRODUCTION, OPERATION, AND MAINTENANCE NORTHERN STATES POWER CO.

Mr. TACHENY. I thank you for the kind introduction. I appreciate it.

At Northern States Power Company, as Dave mentioned, we are headquartered in Minneapolis, Minnesota, we have about 1.5 million electric and gas customers, and cover about 49,000 square miles of territory. In 1986, our energy output to our customers was somewhere in the range of 33,000 gigawatt hours.

We have been conscious of the environment over the years at Northern States Power Company, and as an indication of that in the last 10 years, we have, while increasing our electric production by about 15 percent, we have decreased our output of sulfur dioxide by about 70 percent from our powerplants.

I have brought with me, and have entered into the record, information on two of the projects we are involved with.[1] One is a dry scrubber operation, which we pioneered at our Riverside Plant, one of the older units, put into service in 1949 or 1950, a 37-year old unit. This unit was retrofitted with a gas desulfurization system, and it was done for a number of reasons in that case.

The Riverside unit was the first full-scale flue gas desulfurization unit, I believe, in this country. There had been some test models built before that. There were a lot of large-scale models being built and under construction, but this is the first one in operation.

We did it because one of our new large generating units was going to have technology of this type on it, and we saw this as an opportunity to not only clean up one of our old units, but to get some real life experience on the flue gas desulfurization process.

As I said, it was put on a unit that had been in operation for 37 years. Our main incentive was to increase the life of that unit, and gain the operating experience for our operators. The test process for that has been largely completed now. The tests were very successful. The operating experience that we gained from putting this into service, we thought and think, is very useful for us in our new 850-megawatt that will be going into service in the fall of 1987.

The second project that we have just now finished and are in the process of testing is at our Black Dog plant, south of Minneapolis, Minnesota, and this is an atmospheric fluidized bed combustor. NSP built its first fluidized bed combustor back in the mid-70s at a smaller unit in LaCrosse, Wisconsin. It was done there to enable us to burn waste wood products from that area.

It was successful, and because of our desire to learn more about the fluidized bed combustion process for our own needs, and for the industry. Also because of a continuing problem that we had had with the existing boiler equipment at the Black Dog plant, we decided to convert that unit to a fluidized bed combustion boiler. That unit was about 100-megawatt size generating unit. This will be the first conversion of such a boiler to a fluidized bed combustor.

Our incentives in that case, again, were to solve some problems we had with the boilers, to learn something about the fluidized bed process, and to learn something about burning coal, various types of coal, in a fluidized bed boiler.

We are just now finishing the construction, starting the test program of that unit, and it has not been without problems. But as with any new technology, those are not problems that we didn't expect to see. There are always things that you don't expect, that you have to learn in the process of starting up in a new technology, and we finding that that is true here also. We are very confident that it will work, and we are very confident that we will learn a lot about the fluidized bed process of burning coal.

In the case of the Bad Dog fluidized bed boiler, the tests that we have run to date indicate that we can achieve a reduction in nitric oxides from the flue gas of about 50 percent from the old pulverized coal process, and reductions in sulfur emissions from the unit of about 70 percent from the old pulverized coal process.

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[1] The material referred to has been retained in committee files.

Senator MITCHELL. Thank you, Mr. Tacheny.

Dr. Papay.

STATEMENT OF DR. LAWRENCE T. PAPAY, SENIOR VICE PRESIDENT, SOUTHERN CALIFORNIA EDISON

Dr. PAPAY. Thank you, Mr. Chairman.

My name is Lawrence Papay, Senior Vice President with Southern California Edison Company. My responsibilities there include the design, operation, and the maintenance of Edison's electrical generation and transmission facilities. Before responding to your five questions, I would like to give a little brief overview of the Cool Water project for those who may not be familiar with it.

The Cool Water coal gasification program is the first full-scale demonstration of coal gasification used for the generation of electric power. The facility integrates a gas turbine generator in combination with a heat recovery steam boiler and a steam turbine, to demonstrate the concept of an integrated coal gasification combined-cycle plant.

The program is owned and operated by a private partnership, including Southern California Edison, Texaco, Electric Power Research Institute, General Electric, Bechtel, and a consortium of Japanese companies. There are also two other lesser contributors to the program, ESEERCO and Sohio.

Now let me respond to your five questions.

The first question deals with the removal rates of the technology for sulfur dioxide and for oxides of nitrogen, and how these compare with other technologies.

The environmental performance at Cool Water, which went into commercial operation in June of 1984, has been outstanding. The plant has demonstrated its ability to limit emissions of sulfur dioxide and nitrogen oxide particulates to as low as 10 percent of the allowable levels under the U.S. EPA's new source performance standards.

At Cool Water, more than 97 percent of the sulfur compounds from the gas stream is removed before combustion and converted to elemental sulfur of 99 plus percent purity. Oxides of nitrogen are controlled by saturation of the fuel gas with water, or alternately by steam injection at the combustion turbine.

Cool Water NO_X emissions average only 10 percent of the applicable new source performance standards. Particulate, carbon monoxide and hydrocarbon emissions are practically non-existent. Specific levels of SO_X, NO_X, and particulate emissions for each coal tested are provided in Table 3 on page 23 of my testimony.

I might point out that the solid effluent streams from this plant are two. A slag which has been determined to be non-hazardous by the EPA, as well as by the State of California, and the elemental sulfur whose purity actually allows us to sell it at a premium since its purity is 99-plus percent.

Your second question deals with how long these technologies have been used, on what scale, what applications, and will they soon be commercially available.

Gasification itself is an old technology, but the Cool Water plant is the first time that this has been brought to a commercial scale coupled with power generation.

The specific gasification technology that we use at Cool Water is the Texaco gasifier. They have some 80 units in operation worldwide, using a variety of feedstocks. There are three units which use coal as a feedstock at what I will call a commercial level, one in Tennessee, one in Germany, and one in Japan.

The third question in your letter addresses the cost of the technology. Of course, there are a variety of cost estimates which have been done, principally by EPRI, and their latest cost estimate compares the Cool Water type technology in what I will call second generation, using the new gas turbines, with pulverized coal plants using best available control technology on a size of about 500 to 700 megawatts, because this is the economically scalable size for pulverized coal.

I should point out, however, that the IGCC plants are modular in design and can be installed in smaller modules in the order of 100 to 150 megawatts. Modularity can save capital investment and, as such, can provide a construction cost advantage.

Recent studies are just being completed at EPRI which show that, on an operational basis, the Cool Water technology can compare favorably with pulverized coal, and perhaps even have a slight cost advantage over a thirty-year basis.

Question four deals with retrofit. The primary purpose of the Cool Water technology is for new plants. For repowering, there are some advantages in Cool Water if the costs prove out on a case-by-case basis. As far as retrofit, it can be done technically, but I am not sure the economics would be there in each case.

Finally, in terms of question five on the experiences that we have had with this technology—our confident and concerns. We, of course, feel quite confident with the technology because we have been operating it for nearly three years.

I think that it is safe to say, as far as other utilities are concerned, that they are conservative, and no utility wishes to build a first of a kind commercial plant which could cost hundreds of millions, or a billion dollars or so. This is particularly true, given the regulatory overview of construction costs, and the potential for stockholder liability of perceived cost overruns in today's environment.

Although we started the program with slightly different objectives, we do feel that the program is applicable to the questions you have in front of you today, and we stand ready to work with any utility on the East Coast, or the Federal government, if you would like, to do proving out of this technology for eastern coals.

We have tested a couple of eastern coals, but they have been short-term tests. Being located in California, we have been using a Utah coal as a program coal.

I see my time is up, so I will stop at this point. Thank you.

Senator **Mitchell**. Thank you, Dr. Papay.

Our next witness is Mr. Paul LaHaye, Chief Executive Officer, The Hague Corporation, which is in South Portland, Maine. Mr. LaHaye care to Maine with the General Electric Corporation many years ago, and he had the good sense to stay after GE left.

Before I ask you to testify, Mr. LaHaye, I note the presence of Senator Simpson.

Senator, welcome. Do you have an opening statement that you would care to make?

OPENING STATEMENT OF HON. ALAN K. SIMPSON, U.S. SENATOR FROM THE STATE OF WYOMING

Senator SIMPSON. George, I thank you.

First, I have a statement from Carbon Fuels Corp. outlining a process for refining coal that I would like entered into the record, if I may, Mr. Chairman.

Senator MITCHELL. It will be done. (See p. 262.)

Senator SIMPSON. Secondly, I just want to tell you that I am very appreciative of your holding this hearing regarding this issue. It is one that we just can't continue to duck. We do our work in here, but then we never do any work on the floor.

I think that it is very important that we get to it, and I am heartened that you are in this role. I hope that we can get to something, with a blend of Senator Stafford's bill, your bill, and the Proxmire/Simpson bill, which I have joined with, which is a mandate of a 10 million ton reduction.

I think that we can do it, if we do it with flexibility, and giving people, instead of a mandatory way of doing it, the options or the blend, if you will, of conservation, clean coal technology, enhanced combustion technology, and low sulfur coal, the scrubbing, or whatever.

I really pledge to work with you to bust this legislative gridlock on this one that we have seen for six years. You and I have both been frustrated. I think that we can get a good bipartisan bill here that will appeal to most of us, and know you, it will be done in a very fair and responsible manner.

Senator MITCHELL. Thank you very much, Senator. We look forward to working with you on that.

Mr. LaHaye, you came in after we started this panel, so I will repeat for you. We ask the witnesses to limit their oral remarks to five minutes, and you will know that the five minutes are up when this red light goes on.

Mr. LaHaye, welcome, and we look forward to your testimony.

STATEMENT OF MR. PAUL G. LAHAYE, CHIEF EXECUTIVE OFFICER, THE HAGUE CORP.

Mr. LAHAYE. Mr. Chairman and Members of the Committee. I first want to apologize on behalf of Eastern Airlines for getting me here two hours late.

The Hague International, as Senator Mitchell indicated, is a small corporation manufacturing hardware, and also involved in developing high temperature process equipment. The corporation, you might say, is one of an endangered species right now.

The question of acid rain touches on such a varied and diverse interest group that orchestrating a social and economic solution undoubtedly will require a substantial amount of effort by all of us.

Anyone who has first-hand experience with the use of sulfur bearing fuels and has experience in the environmental impact of unrestricted emissions from the combustion of such fuels must have an interest in these proceedings.

When the oxides of nitrogen were first identified as undesirable elements in the effluent from various combustion processes, we knew very little about their formation in the combustion process. A decade later, we have the means of making five to one, and in some instances ten to one, reductions in these emissions at very little cost.

We expect that the same thing will happen with the oxides of sulfur, that we will learn to do this by the early 1990s. We would expect that a variety of technical solutions will be at hand to make reductions in emissions from major sources of magnitudes similar to that which has been realized with NO_X.

Under the auspices of the Federal Government, the utility industry and equipment manufacturers, a substantial amount of coal combustion research was conducted in the United States as part of the high heat hydro-dynamic research effort. While this work extends over three or four decades, the bulk of the useful combustion work has been conducted over the past decade.

This research has provided a thorough understanding of the coal combustion process and has yielded a number of embryonic hardware solutions. The hardware solutions show promise of providing substantial reductions in SO_X emissions by removing the sulfur during the combustion process. The hardware to which I refer are slagging combustors.

With the current hiatus in the nuclear power area, and despite the present abundance of natural gas and the oversupply of crude oil, as a nation we have all accepted the need to increase our dependence on coal as a fossil fuel of choice for the electric power generation well into the next centuries.

Simultaneously, we have generally concluded that the combined cycle, consisting of a gas turbine with a steam bottoming cycle, is the power conversion cycle of choice. This cycle is attractive to utilities principally because it is reliable, low in cost, and high in efficiency. Unfortunately, the fuel of choice, coal, is not compatible with the power cycle of choice. Coal cannot be burned directly in a high performance gas turbine without destroying the turbine in a short period of time.

We have spent many millions of dollars trying to burn coal and other ash burning fuels in gas turbines directly. Since the 1950s, the idea of burning coal in gas turbines has risen from its own ashes on a 7 to 10-year cycle. We keep trying and we keep failing.

An equally consistent and recurring theme is to chemically process the coal into an acceptable form that is compatible with gas turbines. Simultaneously, in the same process, we remove the sulfur and make the resulting fuel environmentally acceptable. This we have succeeded in doing, and the first operating plant, Cool Water, has proven the technical feasibility of the coal gasification concept.

Coal gasification is an ideal environmental solution, but appears to be economically limited. It is a single power generation installation of blocks of 200 megawatts or greater. Many electric utilities need smaller blocks of power than 200 megawatts.

It was evident in the 1960s, it was evident in the 1970s, and it is now clearly essential that we provide the utility industry with an environmentally acceptable coal burning, economically viable, high efficiency power conversion cycle, rated between 50 and 250 megawatts. Current technology dictates that the power conversion cycle be a high performance gas turbine, with a bottoming cycle, burning coal with either front-end or back-end cleanup of emissions.

What we have, we believe, is all of the necessary technological solutions in hand to meet a 90 percent reduction in sulfur emissions and simultaneously satisfy the objectives of the electric utility industry. The need to demonstrate this emerging technology has been endorsed by more than a dozen electric utilities.

The sponsors of this demonstration are the Florida Power Corporation, the Stone and Webster Engineering Corporation, and ourselves. To date, there is no Federal or State support for this demonstration. We expect to have a 55-megawatt demonstration power plant operational in the 1990s.

The power cycle described above is identified as the externally fired combined cycle. The key is a high temperature ceramic heat exchanger, which was developed by ourselves. I have available copies of technical papers that were originally prepared by Stone and Webster Engineering Corporation and ourselves for the coal technology conference in Pittsburgh last fall, describing the proposed power cycle.

We believe that this cycle, combined with a slagging combustor, will permit public utilities to attain the objectives of high performance, low emissions coal-fired electric power generation within five years that will provide a coupling between the fuel of choice and the power conversion cycle of choice, and in addition permit the utilities to meet the national goal, with eastern coal, of the 90 percent reduction in sulfur emissions.

Thank you very much, Mr. Chairman.

Senator MITCHELL. Thank you, Mr. LaHaye.

The next witness is Dr. F. P. Boer.

STATEMENT OF DR. F. P. BOER, SENIOR VICE PRESIDENT, W.R. GRACE AND CO., ACCOMPANIED BY DR. LOUIS HEGEDUS; RESEARCH VICE PRESIDENT

Dr. BOER. Thank you very much, Mr. Chairman and Members of the Subcommittee, ladies and gentlemen. I appreciate your invitation to address the subject of selective catalytic reduction. With me is Dr. Louis Hegedus, a research vice president of W.R. Grace, and an internationally recognized catalyst expert.

My purpose will be to tell you that a proven catalytic process is available to abate nitrogen oxide emission from stationary sources, especially power plants, and that experienced firms, such as W.R. Grace, will make the commitment to supply the catalysts.

Let me give you some of the background that leads me to make this statement. Grace is not new to the catalyst business. We have roots that go back to World War II, and we have gradually built our business to the point where we are the world's leading catalyst supplier.

Grace is also by no means new to the business of controlling air pollution or NO_X. We entered that business when catalytic converters were mandated on American cars in the 1975 model year. We built a plant in Baltimore, and are now supplying catalysts for about two million converters a year to Detroit.

I am also sure that you will understand that it is important to us to sustain our leadership position and to maintain international competitiveness. To that end, Grace employs more than 200 scientists and technicians in the field of catalysis alone.

Ironically, the commercial development of power plant de-NO_X catalysts took place in Japan for the simple reason that Japan was the first major country to mandate that NO_X be controlled. I say "ironically" because the origins of this technology can be traced to American laboratories. Japan's head start puts us and the rest of the world in a catch-up position.

There can be no doubt that the technical and economic performance of the SCR process has been proven in Japan, where more than 200 coal, oil, and gas-fired plants have retrofitted or original SCR units and are operating today with minimal problems.

Our interest in SCR heightened in 1984 when the German public became alarmed by the "dying forest" issue, and the German Government mandated control of NO_X from both cars and power plants. Grace researchers and engineers moved quickly, and in cooperation with our local partners, we implemented plans that led to the construction of a catalyst plant near Bonn.

Ours is the first plant to go into operation in Germany. This plant is sized to provide catalyst for up to one-third of Germany's 46,000 megawatts of generating capacity that will require control. Note that, in view of the previous discussions we have had, that the time it took, from the time the need was established to the early commercialization stage, was about three years.

I have a sample of this catalyst with me, and I have included in your handout a German advertisement for our product. You will note that in this handout the research base for this business is right here in our neighborhood, in Grace's Washington Research Center.

The driving force in our decision to commercialize this technology in Germany was that it would prepare us to eventually produce catalyst in the United States.

SCR catalysts are installed in large towers, which can be positioned after the boiler, either in front of or behind a deSO_X unit. They perform a simple and clean chemical reaction in which the NO_X is injected with ammonia to form two harmless substances, nitrogen gas and water. In effect, the pollution is destroyed and components of normal air go out the stack. There is no disposal problem.

To be sure there are technical issues in every installation, such as catalyst lifetimes and operating temperatures, but it is safe to say that in the vast majority of cases the SCR process will reliably remove 80 to 90 percent of the NO_X at a cost of five to 15 mils per kilowatt hour. Indeed, it is our understanding that in Germany the costs are expected to be at the lower end of this range.

This line on the chart shows the Japanese federal standard at 200 parts per million. In Japan, many localities have even more stringent controls and impose limits down to 50 parts per million. This line is a 100 parts per million standard and is the West German standard. This area is where the standards are today for current and new sources in the United States.

The curve shows that it takes more catalyst to attain a lower standard and that there is a tradeoff involved. The excess is labeled in pounds per million BTUs.

I would also point out that with regard to the cost problems, our researchers today are looking at ways to make these catalysts cheaper, and the catalysts are a major part of the costs that we are seeing today.

To summarize, SCR is not pie-in-the-sky. It has been proven in hundreds of plants at a scale of up to 1000-megawatts. The decision to implement this technology is a matter of public policy, and it involves difficult tradeoffs of costs and benefits. When that decision is made, however, we, in the catalyst industry, will respond quickly as we did with auto catalysts, to build the production facilities, make the product, and advance the technology.

Thank you.

Senator MITCHELL. Your comments lead directly to my first question in my series of questions for the panel regarding the clean coal program generally.

In 1984, a report to EPA on pollution control technology research and development reached this conclusion, and I will quote:

> While government funding of basic research may work well, government efforts aimed at commercialization too often are a failure.

Do you agree with this conclusion and, if so, how do you apply your answer to the clean coal program?

Why don't we begin with you, Dr. Boer?

Dr. BOER. My feeling is that it is difficult to move forward on a technology until you know what the standards are that you will have to meet. You will have difficulty making effective investments, and justifying those investments, until the rules of the game are known.

I think that this basically answers your question, sir.

Senator MITCHELL. Does any other member of the panel care to comment on that question?

Dr. PAPAY. I think that the problem there is an age-old problem, whenever you talk technology, you are going from demonstration to commercialization.

In most demonstration programs, you get a very nice bar chart, which takes you out through the demonstration phase, and then there is a little triangle which says, "commercial feasibility has now been proven," but you still have a rather sizable inertia, if you like, to overcome to get those first commercial plants in operation simply because of the uncertainty in both costs and in the technology itself.

I am not sure that I have a solution to the problem. I am just pointing out that the problem does exist, and you do have to find individual utilities, if we are talking about this particular problem, who will move forward with the technology.

Senator MITCHELL. Go ahead, Mr. LaHaye.

Mr. LAHAYE. We are one of the few organizations that attempted to demonstrate commercially a solution for the steel industry, supported by the Department of Energy, about six or seven years ago. We placed on the market some 20 large pieces of equipment with the intent of receiving an insurance policy from DOE regarding the life and the operating expense of the hardware.

It turned out to be a total disaster because a segment of the organization that we were dealing with did not understand the commercialization of the product and were very slow in responding. The bureaucracy got in the way, so we ended up doing it ourselves. I would recommend that any government agencies stay out of the demonstration business, if they can.

Senator MITCHELL. What do you think of the way the DOE has handled the clean coal program, generally?

Mr. LAHAYE. I don't have enough experience with the clean coal program at this date. However, I would expect that what is happening is that they are doing more of what is the obvious technology that existed four or five years ago than technology that is on the forefront at the moment.

Senator MITCHELL. The same report, to which I earlier referred, included this statement, and I quote again:

> Many of EPA's statute require that technology be demonstrated before EPA can lower emission standards. As a result, EPA is left in the situation where it cannot tighten standards unless it can demonstrate that technology is available, and the private sector cannot be sure it will use or be able to sell a low emissions technology until EPA has promulgated a low emission standard. In the absence of a Federal control technology development demonstration program, EPA is in a catch-22 situation.

Do you agree that they are in a catch-22 situation specifically in the development of air pollution control technology, and do you believe specifically that the clean coal program suffers from this problem?

Dr. Boer, and then anyone else who wants to comment can.

Dr. BOER. I would comment initially on the NO_x situation where our expertise lies. I don't think that SO_x is a major problem because commercial demonstration of the technology has already taken place.

I think the real issues with regard to NO_x have to do with how much attention has been paid to technical problems such as the brown coal and slagging boiler cases, which are on the way to solution in Germany, and which we are confident can be solved in the timeframe required.

It is true that all of the problems can't be solved, with demonstration that they can be solved, but it is reasonable to assume that most of them will be solved when there is a commercial incentive. My view is that the existence of some unsolved problems can be pushed to the point where it is used as a delaying tactic. But in the case of the NO_x side of the equation, the only one I would like to address, I think that the technology is indeed ready. It is true that more advanced technologies are coming, we ourselves are working on them at Grace, and many of them can be retrofitted into existing plants. Basically, we are ready to go.

Senator MITCHELL. Thank you.

Dr. Papay, do you wish to comment on that?

Dr. **Papay**. Yes, generically speaking, I think that this is the case because of the way the Clean Air Act was written.

I might point out that I do serve on the Department of Energy's Energy Research Advisory Board, and two years ago, we did do a Clean Coal Technology Task Force Panel Report, and we came to very similar conclusions as far as the question of implementation, that the Federal Government had backed off from the demonstration programs and, in fact, there needed to be an infusion of additional funds, above and beyond what was originally allocated in clean coal technology, simply because you are dealing with a very large, heterogeneous industry with utilities spread all over the United States, different constituencies, different coal sources, and what-have-you. The fact does remain that there is inertia in commercializing these technologies.

Senator **Mitchell**. Thank you very much.

Go ahead, Mr. Tacheny, give a brief answer because my time is up, and I want to yield to my colleagues.

Mr. **Tacheny**. I was just going to say that at Northern States Power Company, we, in Minnesota, always faced very low restrictions on air discharge. It does become a problem to go from demonstration to commercial operation of scrubbers, whether they are wet scrubbers or dry scrubbers.

We put wet scrubbers on our two 750-megawatt units at our new plant in 1976 and 1977, and we are still modifying those today because of problems in operating them, because of problems in costs, and maintenance concerns with those. From demonstration to commercial is a big step.

Senator **Mitchell**. Thank you.

[A letter from Mr. Kennedy follows:]

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March 5, 1987

The Honorable George J. Mitchell
United States Senate
Committee on Environment & Public Works
Room 406, Dirksen Senate Office Building
Washington, DC 20510

Dear Senator Mitchell:

I respectfully submit the following statements as follow-up to the March 4, 1987 Environmental Protection Subcommittee hearing.

During the question period for Panel II, you asked Dr. Peter Boer a question regarding the commercial readiness of retrofit technology for the removal of nitrogen oxides and sulfur oxides from coal combustion flue gas. Dr. Boer replied properly that the Grace SCR process for removal of nitrogen oxides was commercially demonstrated in Japan and West Germany as retrofit technology and was ready for application in the United States.

However, regarding sulfur oxides, Dr. Boer replied briefly that the Grace SCR technology was not applicable to removal of sulfur oxides and that other technology would be required. In order to amplify that point to prevent a misunderstanding by the Subcommittee, you should be aware that sulfur oxides removal from flue gas is commercially demonstrated - using wet flue gas desulfurization (scrubbers) - but is applicable only in certain site-specific retrofit situations.

The other retrofit sulfur oxides removal technologies (boiler limestone injection, LIMB, sorbent injection into the flue gas prior to the electrostatic precipitators - Coolside, Dravo's HALT process, Bechtel's CZD process, etc.) remain to be demonstrated on a commercial scale. Several demonstrations will be completed in the next few years utilizing combined private industry, state, and federal funds; only at that point will the technologies be viewed as being ready for commercial retrofit application.

Thank you again for the opportunity to review Consolidation Coal Company's activities in SO_2 abatement technology development.

Very truly yours,

F Kennedy

Flynt Kennedy
dhc

Senator MITCHELL. Senator Stafford.

Senator STAFFORD. Thank you, Mr. Chairman.

Dr. Boer, I listened carefully to what you had to say because I understand your wife is from Vermont.

Dr. BOER. That is right, sir.

Senator STAFFORD. I was impressed with what you testified to with respect to the SCR catalyst. I noticed that it seemed to refer mostly to nitrous oxides. Does it also have something to do with sulfur oxide?

Dr. BOER. It has nothing to do with sulfur oxides. Our technology would have to be used in conjunction with an SO_x scrubber, and that is the usual way that it is installed, sir.

Senator STAFFORD. Thank you, I wanted to make sure that I understood that.

Mr. LaHaye, would it be possible, very briefly, for somebody who isn't really up on these things, to tell us what a slagging combustor is?

Mr. LAHAYE. The slagging combustor is an outgrowth of the High Temperature Hydro-Dynamics Program. It is a combustor that operates using a powdered coal. It operates in a fashion that raises the temperature of the combustion process to the point where you can separate out the ash by centrifugal means or by simply impact on a wall.

Senator STAFFORD. The atmospheric fluidized bed combustion is that a slagging combustor?

Mr. LAHAYE. No, it is not. It is a different process. The slagging combustor does give us the advantage of being able to operate at much higher temperatures than the fluidized bed. Most thermal cycles are dependent on the temperature for efficiency.

Senator STAFFORD. Thank you.

Mr. Chairman, I used some of Senator Chafee's time, so I will yield to him.

Senator MITCHELL. Senator Chafee.

Senator CHAFEE. Thank you, Mr. Chairman.

Listening to this panel, one comes away quite upbeat on what the technologies are, these different control technologies that you have described.

Would each of you characterize your technology as to whether it is primarily for retrofit of old facilities, or primarily for new, or can it go either way, for retrofit and new plants.

Mr. LaHaye, how would you characterize yours?

Mr. LAHAYE. Senator Chafee, the technology that we represent is really an energy conversion cycle. We are borrowing from the MHT work on the slagging combustor to accomplish the environmental function. The concept has been around since the invention of the gas turbine. The idea is simply to burn the fuel externally of the cycle, rather than in the gas turbine itself. It gives you a great deal more flexibility.

Senator CHAFEE. So it could be retrofit or new plant.

Mr. LAHAYE. Either way.

Senator CHAFEE. Just one little other question. What is Magneto-Hydro-Dynamic Research?

Mr. LAHAYE. It appeared in the backside of the textbook I had for thermal dynamics when I graduated from college, and I hate to say how long ago that was. It has been around as a tool to make electricity directly from an ionized gas stream.

Senator CHAFEE. Why do you capitalize it? Is it some specific research program?

Mr. LAHAYE. No, a series of them, and they are still going on, actually.

Senator CHAFEE. Sponsored by various universities?

Mr. LAHAYE. Utilities, universities, the government, and DOE has sponsored some.

Senator CHAFEE. Back to the retrofitting or equipment for new plants, how about your technology, Dr. Papay?

Dr. PAPAY. Senator, its primary purpose would be for new plants. We had demonstrated the ability to take the gas products, and it is a conversion process, and we fired it in an existing utility boiler at that same site.

I would say that its primary purpose is new plant. If you are repowering an existing plant, it would be secondary. Retrofitting would be really at the bottom of the list, and it would be very site dependent because it does involve a new conversion process of converting that coal into medium BTu gas.

Senator CHAFEE. Mr. Tacheny.

Mr. TACHENY. The two technologies that I talked about, Senator, are not ours. They are technologies developed by manufacturers, and we worked with those manufacturers to test them in full scale operations in both cases.

The fluidized bed technology that we used to retrofit one of our boilers can certainly be applied to new boilers, as TVA is doing in building a new atmospheric fluidized bed combustor. In our case, we have a lot of boilers that we believe the retrofit of this kind of technology would be very useful to, to help us to life extend those units, and to help us to meet the compliance with those units.

Up until the time we started building the fluidized bed combustor, our method of reaching compliance with regard to sulfur emissions was to switch coals, to go from Illinois coals, which were higher in sulfur by about 3.5 percent, to western coals pretty much, and we were able to meet our air discharges by those means, but we suffered derates on these units in the process. This allows us not only to stay in compliance, but gain derates back, and so on. We have used it in retrofits pretty much.

Senator CHAFEE. Dr. Kennedy.

Dr. KENNEDY. The work that we have done was directed primarily toward retrofits because of our being a coal producer, and we want to be able to help solve our customers' problems as they come.

The reason that we have a variety of options that we are looking at is because not every boiler is the same, and you get caught up in a great deal of very site specific analyses. The more options that we can put on the table for the customer, we feel, the better choice and decision he will make.

Senator CHAFEE. Dr. Boer.

Dr. BOER. It is clearly and demonstrably a retrofittable technology, and you can always use that in a new plant as well. In fact, there is substantial flexibility as to how you retrofit to take into account local conditions. The best way, perhaps, is to have it in front of the deSO$_X$ unit, which at least technically does not derate the plant. You just put in a large fan, and in effect blow the gas through this large tower, and then move it on to the SO$_X$ scrubber. There are no moving parts in the tower, and the catalyst probably won't have to be changed for many years.

It is a very simple process, and it certainly lends itself to a retrofit, and it has some flexibility.

Senator CHAFEE. My time is up. Thank you, Mr. Chairman.

Senator MITCHELL. Senator Durenberger.

Senator DURENBERGER. Thank you, Mr. Chairman.

Mr. Tacheny, I am under the impression that the fluidized bed technology is most appropriate in a repowering case where you are refurbishing a plant, and I think you may have given us an example of that, to extend the life of the plant. Is that a generally accurate statement?

Mr. TACHENY. Generally, in our case, this has been true. We have a lot of plants that are in the 100 to 200-megawatt size that are now getting rather old. We believe that it is going to be difficult to commission a site to build plants on, at least in our service territory, and also expensive.

We believe that the way to go for us is to extend the life of the plants that we have as much as we can, and to use this fluidized bed technology in doing that, where appropriate. It is not appropriate for all utilities.

Senator DURENBERGER. Let me ask you a question that relates to extending the life of a plant, and the utilization of the fluidized bed technology, and the new source performance standards.

What would be the impact, in your opinion, on the future of fluidized bed technology if the Congress required that all plants meet the NSPS requirement on something like their 30th or 35th birthday?

What is the technological capability of fluidized bed technology to meet NSPS standards, in your opinion?

Mr. TACHENY. I would say, from our experience today in putting the fluidized bed into service, and with the problems that we have had with starting it up, that there is a lot to be learned yet about working and operating fluidized bed boilers. It is not something that is immediately ready to go as an available answer.

In the next 5 to 8 years, I would say that certainly may not be true anymore. We are learning a lot right now.

Senator DURENBERGER. Suppose, in the alternative, that we required all plants to meet straight emission limits when they reach a certain age, would you have some advice for us on where we could set that limit and still make room for fluidized bed technology?

Mr. TACHENY. I am sorry, Senator, I am not familiar with the number that we are working with in Minnesota, but I believe it is 1.2.

Senator DURENBERGER. Maybe we could get an elaboration on that.

Mr. TACHENY. Yes, I will be happy to bring that back to you.

Senator DURENBERGER. Another alternative or another approach, are there appropriate combinations of retrofit and repowering technologies, say, coal cleaning plus fluidized bed, that in your opinion might meet the NSPS standards at some cost less than the cost of scrubbers?

Mr. TACHENY. At Northern States Power Company, the air discharge limits in our territory, we have found that we have been able to meet economically by switching coals, but we are located geographically where that works pretty well for us. It may not work that well for others located farther east, and so on. We have been able to meet the limits with coal switching, and that is less expensive for us than adding either wet scrubbers, dry scrubbers, or converting to a fluidized bed.

To meet new source standards on new units, and when the times comes to renovate existing equipment, then certainly the fluidized bed, we think, is the way that we will be looking in order to meet those new source standards. It gives us the ability to not only rejuvenate the equipment we have, but to, perhaps, go back to some of the higher BTu fuels and burn a wider variety of fuels than we are now able to burn in our units.

Senator DURENBERGER. As the final answer for the record, if we want to drive technology by setting an emission limit for plants in a life extension program of that kind, where would you recommend that we set that limit and why?

If you could just explore that one for the record, I think that it would be helpful.

Thank you very much.

Senator CHAFEE. Gentlemen, let me just ask you one question. As I understood what Dr. Boer was saying, and the rest of you seem to echo, certainly Mr. LaHaye, is that it is very difficult to go into the production of some kind of unit that would be required until the EPA sets the standards that it wishes to have achieved.

At the same time, EPA doesn't want to require the equipment, or set forth the standards, because they are not sure that you folks can produce the equipment. Is that basically what you are saying?

Mr. LAHAYE. That is correct. Certainly the first part is correct.

Senator CHAFEE. The chairman characterized that as EPA being in a catch-22 situation, but I would also say that it puts you folks in a catch-22 situation.

You indicated, Mr. LaHaye, that you went ahead and produced some equipment, but you said that it was disaster, why was that?

Mr. LAHAYE. In this case, the Department of Energy changed its mind half-way through the program. We had a commercial obligation to our customer, so we had to use our own money to complete the program.

Senator CHAFEE. Are you folks saying that if EPA would set forth some tough standards, which fall within the limits which you have discussed, then you would go ahead and produce the material. Is that right?

Dr. BOER. That is correct. If the standard were somewhere in the range of the Japanese or the German standards, we would go ahead. If the standard was twice as high as that, we probably would say that this is not the right technology for the country, and we might pull back on those programs as far as the U.S. part of it is concerned. But, of course, we are investing for the German end of our business. So our business opportunities in the U.S. would be very much dependent on the standard.

Senator **Chafee**. Dr. Boer, you talked about the European performance, and I guess the Germans burn pretty much a brown coal, don't they?

Dr. **Boer**. They burn a mixture of coals. The brown coal is a fairly significant coal fraction in Germany, and it is the most difficult to burn.

Senator **Chafee**. Is it higher in sulfur?

Dr. **Boer**. Yes.

Senator **Chafee**. Would you say that the Europeans are taking some very significant steps in reducing these emissions, which we are not doing here in the United States?

Dr. **Boer**. In Germany, yes. They are taking some very aggressive stances on the elimination of the nitrogen oxides and the sulfur oxides as well.

Senator **Chafee**. Is anybody here prepared to argue with that conclusion based on your own experiences of what you have seen abroad, or haven't you have the occasion to see that?

Thank you all very much. I must say that this is technical material, and we will do our best to absorb it. We appreciate a great deal each of you taking the time to come.

This concludes the hearing.

[Whereupon, at 11:50 a.m., the subcommittee adjourned.]

[Statements and other material submitted for the record follow:]

STATEMENT OF MICHAEL D. HIGH, DIRECTOR
DIVISION OF ENERGY DEMONSTRATIONS AND TECHNOLOGY
TENNESSEE VALLEY AUTHORITY
BEFORE THE
SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
UNITED STATES SENATE
MARCH 4, 1987

MR. CHAIRMAN, I AM MICHAEL D. HIGH, DIRECTOR OF THE DIVISION OF ENERGY DEMONSTRATIONS AND TECHNOLOGY OF THE TENNESSEE VALLEY AUTHORITY. TVA IS ONE OF THE LARGEST COAL-BURNING POWER PRODUCERS IN THE UNITED STATES AND A RECOGNIZED LEADER IN DEVELOPING CLEAN COAL TECHNOLOGIES. AS A CORPORATE AGENCY AND INSTRUMENTALITY OF THE UNITED STATES GOVERNMENT, TVA IS CHARGED WITH PRODUCING, DISTRIBUTING, AND SELLING ELECTRIC POWER AT THE LOWEST FEASIBLE PRICE. BUT IT IS ALSO CHARGED WITH FURTHERING THE PROPER USE, CONSERVATION, AND DEVELOPMENT OF THE NATURAL RESOURCES OF THE TENNESSEE VALLEY REGION AND PROVIDES FOR THE GENERAL WELFARE OF ITS CITIZENS. IT IS FROM THIS DUAL PERSPECTIVE THAT TVA HAS PIONEERED MUCH OF THE WORK IN CLEAN COAL TECHNOLOGIES AND WHICH MAKES IT UNIQUELY QUALIFIED TO SUBMIT THE FOLLOWING STATEMENT REGARDING THESE TECHNOLOGIES.

TVA APPRECIATES CONGRESS'S RECOGNITION OF THE IMPORTANCE OF ADVANCING A WIDE VARIETY OF CLEAN COAL TECHNOLOGIES WHICH CAN PROVE COST EFFECTIVE IN MEETING CLEAN AIR STANDARDS AS THEY NOW EXIST OR AS THEY MAY BE MODIFIED IN THE FUTURE. EVEN WITH A HEALTHY NUCLEAR ELECTRICITY GENERATING OPTION, THE UNITED STATES WILL CONTINUE TO DEPEND HEAVILY ON COAL TO MEET FUTURE ELECTRICITY NEEDS.

FOR THE NEAR TERM (1987 TO 2000), THE DIRECTION OF THE FEDERAL CLEAN COAL TECHNOLOGY PROGRAM MUST ADDRESS THREE SIGNIFICANT RELATED ISSUES: (1) PLANT AGE OR RETROFIT, (2) DEGREE OF COMMERCIALIZATION OR AVAILABILITY, AND (3) EFFICIENCY OF POLLUTANT CONTROL. EACH OF THESE ISSUES BEARS ON WHETHER A PARTICULAR TECHNOLOGY WILL PROVE TO BE COST EFFECTIVE AND WHETHER IT WILL TRULY BE USEFUL IN THE EFFORT TO FURTHER REDUCE POWER PLANT EMISSIONS.

TVA BURNED 30-MILLION TONS OF COAL IN 1986, AND WE FORECAST COAL BURNS IN THE 1987 TO 2007 TIMEFRAME RANGING FROM 28- TO 38-MILLION TONS A YEAR DEPENDING ON DEMAND. THIS COAL FUELS A FOSSIL SYSTEM WITH A TOTAL ELECTRIC GENERATION CAPACITY OF 17,650 MEGAWATTS. OF THIS CAPACITY, APPROXIMATELY 40 PERCENT, OR 6,700 MEGAWATTS, WILL BE ABOUT 40 YEARS OLD IN THE 1990 TO 1995 TIME PERIOD. THIS REPRESENTS 42 OF 50 UNITS IN THE 150- TO 500-MEGAWATT SIZE RANGE.

OBVIOUSLY, OUR EXISTING FOSSIL SYSTEM HAS AGED, YET THE DEMANDS FOR ELECTRICITY ARE SUCH THAT WE MUST CONTINUE TO USE IT. ON A NATIONAL LEVEL, THE SITUATION IS SIMILAR. THERE ARE SOME 200,000 MEGAWATTS, OR TWO-THIRDS, OF THE COAL-FIRED CAPACITY IN THE EASTERN UNITED STATES, WHICH HAVE THE POTENTIAL TO UNDERGO SOME FORM OF LIFE EXTENSION OR REPOWERING IN THE 1990S TO BE ABLE TO CONTINUE TO MEET DEMANDS IN THE 2000S. CONSEQUENTLY, IT IS CLEAR THAT ELECTRIC UTILITIES WILL CONTINUE TO BURN MUCH OF THE COAL USED IN THE UNITED STATES.

IT IS IMPERATIVE THEN THAT, IF ACID RAIN LEGISLATION IS PASSED, THE ELECTRIC UTILITY INDUSTRY POSSESS A MENU OF CONTROL TECHNOLOGIES THAT IS RELIABLE AND COST EFFECTIVE FOR REMOVING SULFUR DIOXIDE AND NITROGEN OXIDE AND WHICH TAKES INTO ACCOUNT THE NEED TO OPERATE OLDER UNITS. THE NEED FOR A MENU OF OPTIONS IS APPARENT WHEN THE CONSIDERATION THAT RETROFITTING AN EXISTING PLANT IS VERY SITE AND PLANT SPECIFIC. LISTED IN TABLE 1 ARE SOME OF THE KEY PARAMETERS AFFECTING THE RETROFIT APPLICATION.

THE UNFORTUNATE FACT IS THAT SOME EXISTING PLANTS SIMPLY CANNOT ACCOMMODATE SOME TYPES OF CONTROL TECHNOLOGIES, AND TO MANDATE THE USE OF A PARTICULAR TECHNOLOGY COULD MEAN THAT A BADLY NEEDED PLANT MAY BE SHUT DOWN IF THE LAW IS TO BE OBEYED.

THE GENERAL GUIDELINES FOR CLEAN COAL TECHNOLOGY PROJECTS SET FORTH IN SENATE REPORT 99-82 CLEARLY RECOGNIZE THE NECESSITY FOR DEMONSTRATING COMMERCIAL FEASIBILITY. OF THE NINE INITIAL PROJECTS SELECTED BY THE DEPARTMENT OF ENERGY'S (DOE) CLEAN COAL TECHNOLOGY PROGRAM (TABLE 2), THREE PROJECTS WOULD DEMONSTRATE A NEAR-TERM, RETROFIT TECHNOLOGY FOR THE ELECTRIC UTILITY INDUSTRY--THE LIMESTONE INJECTION MULTISTAGE BURNER (LIMB)/INDUCT INJECTION PROCESS; ADVANCED, AIR-COOLED, CYCLONE COMBUSTOR; AND A COMBINATION GAS-REBURNING AND SORBENT-INJECTION PROCESS.

THE PROPOSAL ABSTRACTS INDICATE THAT THE SCALE OF THESE RETROFIT PROJECTS RANGES FROM 105 MEGAWATTS FOR THE LIMB PROJECT TO A SINGLE 1-TON-AN-HOUR COAL COMBUSTOR FOR THE ADVANCED-COMBUSTOR PROJECT. THE SCALE OF THE REMAINING LONGER TERM TECHNOLOGY PROJECTS FALLS IN THE 5- TO 70-MEGAWATT SIZE RANGE. WHILE THE SCALE OF THE LIMB PROJECT AND THE GAS-REBURNING PROJECT (UP TO 117 MEGAWATTS) SHOULD BE OF SUFFICIENT SIZE TO PROVIDE COMMERCIAL COST AND PERFORMANCE DATA, THE REMAINING PROJECTS MAY NOT BE LARGE ENOUGH TO ADEQUATELY ADDRESS FULL-SCALE COST AND PERFORMANCE ISSUES.

ANOTHER MAJOR FACTOR FOR SELECTION OF A CLEAN COAL TECHNOLOGY IS, OF COURSE, ITS ABILITY TO COMPLY WITH ENVIRONMENTAL REGULATIONS. THE SELECTED PROJECTS, WHICH ARE DESIGNED TO DEMONSTRATE NEW APPLICATIONS, SUCH AS PRESSURIZED FLUIDIZED BED COMBUSTION, COAL LIQUEFACTION, AND INTEGRATED COAL GASIFICATION COMBINED CYCLE SYSTEMS, APPEAR TO BE CAPABLE OF MEETING NEW SOURCE PERFORMANCE STANDARDS WHICH REQUIRE 90-PERCENT REMOVAL AND COMPLIANCE WITH A 1.2-POUND SULFUR DIOXIDE PER MILLION BTU STANDARD. HOWEVER ALL OF THE SELECTED RETROFIT TECHNOLOGIES HAVE A SULFUR DIOXIDE REMOVAL POTENTIAL OF ONLY 50 TO 60 PERCENT WHILE SULFUR DIOXIDE REMOVAL EXCEEDING 70 PERCENT WOULD BE REQUIRED TO MEET A 1.2-POUND SULFUR DIOXIDE PER MILLION BTU STANDARD WHILE BURNING MEDIUM- TO HIGH-SULFUR COALS. CONSEQUENTLY, IF A 1.2-POUND SULFUR DIOXIDE PER MILLION BTU STANDARD IS MANDATED FOR EXISTING UNITS, TVA AND MANY OTHER UTILITIES WOULD FIND LIMITED APPLICATION OF THE LIMB AND OTHER SORBENT-INJECTION TECHNOLOGIES.

IN PART, BECAUSE OF SUCH LIMITATIONS, TVA HAS CONCENTRATED ITS RESEARCH EFFORTS ON THESE KINDS OF CENTRAL TECHNOLOGIES. SINCE THE EARLY 1970S, TVA HAS CONDUCTED RESEARCH ON TECHNOLOGIES DIRECTED TOWARD REMOVING SULFUR DIOXIDE FROM UTILITY POWER PLANT FLUE GASES. OVER 100,000 HOURS HAVE BEEN ACCUMULATED AT TVA PROTOTYPE RESEARCH FACILITIES STUDYING BASIC AND EVOLUTIONARY WET LIMESTONE SCRUBBER PROCESSES AND ADOPTING DRY LIME SCRUBBERS TO TREATING MEDIUM- TO HIGH-SULFUR EASTERN BITUMINOUS COALS. LIMESTONE SCRUBBERS (AND MODIFICATIONS TO THIS BASIC TECHNOLOGY, SUCH AS ORGANIC ACID PROMOTED LIMESTONE AND DUAL ALKALI) ARE NOW COMMERCIALLY OFFERED SYSTEMS. A NEW DRY LIME (SPRAY DRYER) SCRUBBING RESEARCH AND DEVELOPMENT FACILITY AT A SIZE EQUIVALENT TO 10 MEGAWATTS RECENTLY BEGAN OPERATION AT TVA'S SHAWNEE FOSSIL PLANT IN PADUCAH, KENTUCKY. TVA HAS INVESTED NEARLY $8 MILLION IN THE FACILITY, AND WE ARE FINALIZING COMMITMENTS FROM ONTARIO HYDRO IN CANADA AND THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) TO COFUND A 3-YEAR TEST PROGRAM AT THE FACILITY WHICH SHOULD PRODUCE AN ABUNDANCE OF USEFUL INFORMATION. TVA HAS PROPOSED A 160-MEGAWATT DEMONSTRATION OF THIS TECHNOLOGY AS PART OF DOE'S CLEAN COAL TECHNOLOGY PROGRAM.

ADDITIONALLY, TVA BEGAN THE DEVELOPMENT OF ATMOSPHERIC FLUIDIZED BED COMBUSTION (AFBC) FOR ELECTRIC UTILITY APPLICATIONS IN THE LATE 1970S AND NOW HAS SEVERAL MILLION DOLLARS INVESTED IN THE TECHNOLOGY. THIS EFFORT, ALONG WITH EPRI, DOE, THE COMMONWEALTH OF KENTUCKY, DUKE POWER COMPANY, COMBUSTION ENGINEERING, INC., AND THE ATMOSPHERIC FLUIDIZED BED DEVELOPMENT CORPORATION, WHICH CONSISTS OF SEVERAL OTHER ELECTRIC UTILITIES, COAL COMPANIES, RAILROADS, AND THE COAL INDUSTRY IN GENERAL, HAS LED TO THE CONSTRUCTION OF TVA'S 160-MEGAWATT AFBC DEMONSTRATION PLANT PROJECT AT SHAWNEE. TWO OTHER FULL-SCALE FLUIDIZED BED COMBUSTION DEMONSTRATIONS, ONE OF WHICH IS IN STARTUP TODAY, ARE BEING CONDUCTED NATIONALLY.

THE DRY LIME SCRUBBER IS INTENDED TO ADDRESS THE PROBLEMS OF RETROFIT POLLUTANT CONTROL AND REMOVAL EFFICIENCY, WHILE THE AFBC TECHNOLOGY PROVIDES AN ADDITIONAL OPTION FOR LIFE EXTENSION OR REPOWERING EXISTING FACILITIES. THESE TECHNOLOGIES SHOULD BE AVAILABLE FOR WIDE-SCALE DEPLOYMENT IN THE EARLY-TO-MID-1990S. WE ALSO HAVE PROPOSED TWO NEW PROJECTS IN THE SECOND ROUND OF SOLICITATIONS WHICH ALSO ADDRESS THE MAJOR CRITERIA DISCUSSED ABOVE. ONE PROJECT (HYBRID AFBC) FOCUSES ON IMPROVEMENTS TO THE CONVENTIONAL AFBC TECHNOLOGY. THE SECOND PROJECT IS AN EXTENSION OF THE SPRAY DRYER PROJECT USING A DRY SYSTEM BEING DEVELOPED IN GERMANY. IT HOLDS THE PROMISE OF HIGH SULFUR DIOXIDE REMOVAL EFFICIENCIES.

ALL TECHNOLOGIES, WHETHER OR NOT THEY ARE ALREADY COMMERCIALLY AVAILABLE, SUCH AS THE WET LIMESTONE PROCESS OR NEWER SCRUBBER PROCESSES, WILL HAVE TO COMPETE ON COST, DEGREE OF COMMERCIALIZATION, AND RETROFITABILITY. IN TABLE 3, WE HAVE LISTED A BRIEF ASSESSMENT OF EITHER EXISTING OR DEVELOPING SULFUR DIOXIDE REMOVAL TECHNOLOGIES WHICH EXHIBIT A RETROFITABLE POTENTIAL. AS INDICATED BY THE TABLE, THE REMOVAL CAPABILITIES AND COST EFFECTIVENESS OF THESE TECHNOLOGIES VARY TREMENDOUSLY.

RETROFIT TECHNOLOGIES FOR NITROGEN OXIDE EMISSIONS REDUCTION ARE UNDER VARIOUS STAGES OF DEVELOPMENT. PULVERIZED COAL-FIRED BOILERS CAN BE RETROFITTED IN MOST CASES WITH CONVENTIONAL NITROGEN OXIDE BURNERS TO LOWER EMISSIONS BY 30 TO 40 PERCENT.

NEW ADVANCED BURNERS COULD IMPROVE THIS REMOVAL TO 60 PERCENT. NO BURNER TECHNOLOGY IS AVAILABLE NOW, OR EVEN PROJECTED IN THE NEAR FUTURE, FOR NITROGEN OXIDE CONTROL ON CYCLONE BOILERS. SELECTIVE CATALYTIC-REDUCTION TECHNOLOGY IS WIDELY USED IN JAPAN AND GERMANY ON LOW-SULFUR OIL AND COAL-FIRED BOILERS RESPECTIVELY. HOWEVER, IT HAS NOT BEEN SATISFACTORILY DEVELOPED ON HIGHER SULFUR FUELS (BECAUSE OF PROBLEMS ASSOCIATED WITH AMMONIUM BISULFATE FORMATION) AND ITS INHERENT HIGH RELATIVE COST COMPARED TO COMBUSTION MODIFICATIONS ($8,000 A TON FOR NITROGEN

OXIDE REMOVED VERSUS $150 A TON FOR NITROGEN OXIDE REMOVED) ARE IMPEDIMENTS TO WIDE-SCALE DEVELOPMENT. GAS REBURNING, A TECHNOLOGY INVOLVING THE USE OF TWO FUELS (COAL AND GAS), MAY PROVIDE AN OPTION WHERE COMBUSTION CONTROL IS NOT FEASIBLE OR PRACTICAL. IN TABLE 4 WE HAVE LISTED A BRIEF ASSESSMENT OF THOSE EXISTING OR DEVELOPING NITROGEN OXIDE REMOVAL TECHNOLOGIES DISCUSSED ABOVE. AGAIN, THE COST EFFECTIVENESS OF THESE TECHNOLOGIES VARIES WIDELY.

IN LIGHT OF THE IMPORTANCE OF RETROFITABILITY AND THE SIGNIFICANT DIFFERENCES AMONG CONTROL TECHNOLOGIES, IT IS UNFORTUNATE THAT THE PRIMARY FOCUS OF THE 1986 DOE CLEAN COAL TECHNOLOGY SOLICITATION WAS NOT ON RETROFIT APPLICATIONS WITH EMPHASIS ON COAL-FIRED SYSTEMS. OF THE ORIGINAL 13 EXAMPLES GIVEN IN THE DOE CLEAN COAL TECHNOLOGY PROGRAM OPPORTUNITY NOTICE FOR EMERGING CLEAN COAL TECHNOLOGIES, LESS THAN HALF WERE GENERALLY APPLICABLE TO RETROFIT CASES. CONSEQUENTLY, THE VAST MAJORITY OF PROPOSALS RECEIVED BY DOE RELATED TO "NEW" APPLICATIONS, AND THE SUBSEQUENTLY SELECTED PROJECTS INCLUDED ONLY A FEW RETROFIT TECHNOLOGIES. IT IS OBVIOUS THAT MORE EMPHASIS COULD HAVE BEEN PLACED ON THE RETROFIT NEED.

WE HIGHLY RECOMMEND THAT THE CLEAN COAL TECHNOLOGY PROGRAM REEVALUATE ITS SELECTION PROCESS, EMPHASIZE MODERATE-TO-HIGH EFFICIENCY, LOW-COST RETROFIT SYSTEMS AND FUND THOSE EARLY SUBMITTALS THAT MEET THESE CRITERIA. IF THIS DIRECTION IS FOLLOWED IN THE SECOND ROUND OF SOLICITATIONS UNDER THE CLEAN COAL TECHNOLOGY PROGRAM, THE RESULTS ACHIEVED BY THE PROGRAM SHOULD ADEQUATELY ADDRESS RETROFIT NEEDS FOR ELECTRIC UTILITIES.

OF COURSE, THE FUTURE GROWTH OF THE NATION IS DEPENDENT ON DEVELOPMENT AND DEPLOYMENT OF MORE ADVANCED TECHNOLOGY. TECHNOLOGIES, SUCH AS INTEGRATED GASIFICATION, COMBINED CYCLE/HOT GAS CLEANUP, ADVANCED BUBBLING AND CIRCULATING AFBC, PRESSURIZED FLUIDIZED BED COMBUSTION, ETC., SHOULD BE MADE AVAILABLE IN THE EARLY 2000S AS NEW CAPACITY ADDITIONS ARE REQUIRED. RESEARCH EFFORTS SHOULD THEREFORE BE DIRECTED SO THEY ALSO ADDRESS THE NEW

PLANT APPLICATIONS AS WELL AS THE RETROFIT AND REPOWERING ISSUES. AN ASSESSMENT OF THE ADVANCED TECHNOLOGIES, WHICH OFFER BOTH NITROGEN OXIDE AND SULFUR DIOXIDE REMOVAL RELATIVE TO THE RETROFIT AND REPOWERING APPLICATION, IS LISTED IN TABLE 5. TECHNIQUES, SUCH AS UNDERGROUND COAL GASIFICATION OR LIQUEFACTION, DEPEND DIRECTLY ON WORLD ENERGY PRICES, WHICH MAKES THE TIMING OF THEIR IMPLEMENTATION EXTREMELY UNCERTAIN.

IN SUMMARY, WE BELIEVE THAT NEW CLEAN COAL TECHNOLOGIES MUST BE DEVELOPED IF THE PUBLIC'S DEMAND FOR ELECTRICITY IS TO BE MET IN AN ENVIRONMENTALLY SOUND MANNER. HOWEVER, AN APPROPRIATE MIX OF NEAR- AND LONG-TERM TECHNOLOGIES SHOULD BE FUNDED CONSISTENT WITH THE REQUIREMENTS OF FUTURE LEGISLATION.

TABLE 1

RETROFIT IS SITE AND PLANT SPECIFIC

NEED

- Wider Range of Flexible Options

SITE SPECIFICITY

- Boiler Configuration and Age
- Plant Layout and Location
- Present Controls
- Coal Supply Available
- Disposal Area Available
- Local and State Regulation Levels

Table 2

Clean Coal Technology Program

DOE First Round Selection

Proposer	Technology	Location	Application	Size	Demonstration Time Period	Other Sponsors
Ohio Ontario Clean Fuels, Inc.	Coal/Oil Coprocessing (Coal Liquefaction)	Ohio	Liquid Fuels	12,000 bbl/d	1990	Stearns Catalytic Corp HRI
Energy & Environmental Research Corporation	Gas Reburning and Sorbent Injection	Illinois	Retrofit for SO_x/NO_x Removal	117 MW	NA	State of Illinois GRI
Energy International, Inc.	Underground Coal Gasification	Wyoming	Syn. Gas for Conversion to Liquid Fuels	Proof-of-Concept Test	NA	Stearns Catalytic Corp Rocky Mtn. Energy Co.
General Electric	IG-STIG	Ohio and New York	New Plant	5 MW 50 MW	1989-1995	Niagara Mohawk Peabody Holding Co. Burlington Northern RR Ohio Dept. of Coal Dev. ESEERCO, NYSERDA
M. W. Kellogg	IGCC	Penn.	New Plant	60 MW	1990-1992	General Electric Penn. Electric Co.
Wierton Steel	Kohle-Reduction Process	W.Va.	New Steel Process	330,000 T/yr	-	-
AEP (Ohio Power)	PFBC	Ohio	New Plant	70 MW	1989-1994	-
Babcock & Wilcox	Limestone Injection Multi-Stage Burners w/Coolside Technology	Ohio	Retrofit - SO_x/NO_x Removal	105 MW	1988-1990	EPA, Ohio Edison State of Ohio, Consol
Coal Technology	Advanced Cyclone Coal Combustor	Penn.	Oil to Dry Coal Boiler Conv., Ash SO_x/NO_x Removal	23 million Btu/h	1988	State of Penn. Energy Dev. Authority Penn. Power & Light, So. Calif. Edison

TABLE 3

CLEAN COAL MENU - SO_X CONTROL

LABORATORY OR PILOT PLANT	DEMO. COMPLETE	COMMERCIAL	TYPICAL% SULFUR REMOVAL	RELATIVE COST ($ / TON REMOVED)
-------	-------	WET / LIME LS	85 - 90	500 - 700
-------	-------	WET / ADVANCED	95	500 - 700
BURNER INJECTION	1990	1992	30 - 40	700 - 1100
DUCT INJECTION	1991	1993	40 - 50	-------
-------	-------	DRY / LIME SPRAY LOW-S COAL	75 - 80	1600 - 2000
DRY / LIME SPRAY HIGH-S COAL	1991	1993	75 - 80	400 - 600
DRY / LIME CFB	1992	1994	90 - 95	-------
-------	-------	COAL CLEANING	30 - 40	200 - 300
COAL / OIL COPROCESSING	1990	1992	-------	-------

TABLE 4

CLEAN COAL MENU - NO_X CONTROL

TYPE OF POWER PLANT	LABORATORY OR PILOT PLANT	DEMO. COMP.	COMM.	TYPICAL % REMOVAL	RELATIVE COST ($ / TON REMOVED)
CONVENTIONAL FIRED P.C.	ADVANCED BURNER	1990	1992	60	100 - 150
CONVENTIONAL FIRED P.C.	GAS REBURNING	1992	1994	60	1500 - 2000
CYCLONE FIRED	GAS REBURNING	------	------	------	1500-2000
CONVENTIONAL FIRED P.C.	SELECTIVE CATALYTIC REDUCTION (SCR)	1994	1996	80	5000 - 8000
CYCLONE FIRED	SELECTIVE CATALYTIC REDUCTION (SCR)	------	------	------	4000 - 6000

TABLE 5

CLEAN COAL MENU - SO_x/NO_x CONTROL

LABORATORY OR PILOT PLANT	DEMO. COMPLETE	COMMERCIAL	TYPICAL% REMOVAL	RETROFITABLE ?
DRY / LIME SPRAY ADDITIVE	1994	1996	80 SO_x 60 NO_x	YES, BUT SITE SPECIFIC
-------	IGCC COOL SIDE CLEAN UP	1990	95 SO_x 85 NO_x	NO, MAYBE REPOWERING
IGCC HOT SIDE CLEAN UP	1995	2000	95 SO_x 85 NO_x	NO, MAYBE REPOWERING
-------	AFBC	1994	90 SO_x 50 NO_x	YES, BUT SITE SPECIFIC
-------	CFBC	1994	95 SO_x 80 NO_x	YES, BUT SITE SPECIFIC
HYBRID FBC	1995	2000	90 SO_x 70 NO_x	YES, BUT SITE SPECIFIC

STATEMENT OF

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BEFORE THE
SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION
SENATE COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

Wednesday, March 4, 1987

INTRODUCTORY STATEMENT

Mr. Chairman, Members of the Committee: I am Kurt E. Yeager, Vice President and Director of the Coal Combustion Systems Division of the Electric Power Research Institute (EPRI).

I appreciate this invitation to discuss Clean Coal Technology and its implications for electricity supply and environmental improvement. This program is especially significant for the electric utility industry, and therefore is of great importance to the Electric Power Research Institute.

EPRI was established by the electric utility industry in 1972 to conduct a broad research and development program for the entire electric utility industry and its ratepayers. EPRI's R&D mission is to develop new and improved technologies for electric power production, delivery and use, and to help accelerate their availability insuring an adequate supply of economic, reliable and environmentally acceptable electricity.

EPRI is supported by voluntary contributions from investor-owned, government-owned and cooperatively-owned electric utilities across the nation. Over one-third of EPRI's planned budget in the next five years will be directed to clean coal technology. This is an addition to the $700 million already invested by EPRI on this effort. This commitment is based on the premise that coal utilization and environmental protection are mutually compatible and that improved technology is the key to compatibility. Sound scientific data derived from independent, peer-reviewed research must be developed in a timely manner on topics of environmental concern. In addition, information is required to reliably apply the most cost-effective clean coal technologies meeting the diverse needs of the utility industry.

Current environmental control capabilities must be improved by reducing capital and operating costs and preserving overall plant productivity. The importance of this effort is underscored by the fact that a new, large, conventional coal-fired power plant will typically cost $1.5 billion, with over 30% of this cost being directed toward environmental control. This includes sulfur dioxide (SO_2) scrubbing, particulate control, solid waste disposal, water treatment and plant cooling. These controls in their current form also have a major impact on plant efficiency and reliability.

The emission control debate has been driven by conflicting perceptions about the effectiveness of clean air programs. Since 1973, these programs nationwide achieved a 26% reduction in SO_2

emissions while utility coal use increased 70%. In addition, EPRI analyses conclude that SO_2 emissions will continue to decline under the existing Clean Air Act. In spite of the progress achieved, the political focus is shifting from new sources to the more difficult problem of existing facilities. In essence, the debate concerns which sources should be required to further control emissions, by what means, and at whose expense.

The growing understanding of the complex interaction among pollutants indicates instead that the nation should be concentrating on developing an effective, sustained strategy to continue the substantial progress made in all aspects of emissions control. Especially important is vigorous application of new, clean coal utilization technologies that combine emission control with the combustion or conversion process. The utility industry has led the nation in developing and applying clean coal technology, thus strengthening the likelihood of using coal cleanly in every respect this century.

Recommendations in the recent "Joint Report of the Special U.S./Canadian Envoys on Acid Rain" (The Lewis/Davis Report) reflects this change. First, environmental protection can best be achieved through use of innovative clean coal technology rather than ineffective, "band-aid" plant modifications that compromise both productivity and the environment. Second, accelerated commercial demonstration and implementation of these technologies by regulated utilities will require cost-sharing and other incentives not available today. Third, continued research is required in the ecological and atmospheric sciences to better understand cause and effect relationships.

This is a symbolic change in approach and one which provides an opportunity for a positive solution, building on the utility industry's sustained commitment to resolution of the environmental and economic productivity challenges facing the nation.

Since its inception, EPRI has worked with the Department of Energy (DOE) and its predecessor agencies, the Environmental Protection Agency, and other Federal agencies with energy research and development responsibilities to achieve mutual technical objectives. In the spirit of that long-standing cooperation, EPRI and others recommended an accelerated national program to better understand the environmental issues constraining the use of coal and to demonstrate and promptly apply promising new clean coal technology. This effort would build on activities already underway within the federal and private sectors. It recognizes that a major pacing issue in commercial applications of the new clean coal technologies developed over the past decade is the magnitude of the resources necessary to confidently demonstrate their performance and reliability. This requires an intensive, joint effort by industry and government. My remarks today focus on two principal aspects of this national Clean Coal Technology program; viz.,

1. Why Clean Coal Technology?
2. Clean Coal Technology status and demonstration requirements

WHY CLEAN COAL TECHNOLOGY?

The principle which guides clean coal technology development is that sustained environmental improvement can only be achieved when both emission and cost reduction are achieved concurrently, not pitted against each other. Recognizing this principle, the utility industry, which uses over 80% of U.S. coal production, stands at a threshold of fundamental change in its technological base for power generation. The present commercial coal-fired technology is nearing the end of its development potential and is hard-pressed to respond effectively to the rapid changing requirements being placed on power plants. New power generation options which can meet increasingly stringent siting and environmental demands without sacrificing productivity, and can be rapidly constructed in modular fashion over the range of unit sizes are particularly in demand. The next 10 years will therefore be of paramount importance, both in assuring future electricity supply and in controlling cost. It is in the strategic interests of the utility industry, the environmental community, and Government alike to assure the success of this national program.

These changing institutional constraints have effectively priced new, conventional coal-fired generating capacity out of the market for most utilities. For example, it costs three times more today in constant dollars to install a kW of conventional coal-fired electric generating capacity than in 1967. Only a fundamental improvement in power plant technology can effectively respond to these growing constraints on coal-fired power generation and restore economic progress in electricity production. Clean Coal Technology can prvice this improvement. Failure to meet this challenge will not only sacrifice environmental protection but will undermine national economic competitiveness leading to further erosion of industry and jobs.

The urgency of this joint commitment is underscored by the rapidly approaching challenge to the nation's electricity supply capability (Figure 1). Based on recent experience, we can expect electricity demand to continue to pace economic growth. Satisfying even modest growth during the remainder of the century will require a balanced strategy involving additional improvements in conservation and end use management, greater productivity from existing generation capacity (reliability, heat rate and life extension), plus new generation capacity (Figure 2).

New clean coal technology now under development could reduce the cost of this necessary capacity expansion by more than 50% relative to current experience. The industry's present, temporary, capacity margin provides a valuable window of opportunity for technical transition at minimal risk. The new clean coal technologies can now be introduced through incremental, small scale additions, repowering of existing units, "off-balance sheet" plants, and PURPA cogeneration opportunities. The rate of capacity expansion for the late-1990s and beyond cannot, however, be achieved without advancing the technology to much larger scale additions. It is therefore essential that this present opportunity be used to gain the experience and confidence necessary to meet the future capacity expansion challenge and to reduce the cost of electricity as the primary power source for our nation's economy (Figure 3).

In order to reduce the disadvantages facing conventional coal-fired power plants, clean coal technology development in the United States has pursued two primary objectives; viz., to

A. Provide an array of retrofittable emission control options which satisfy, at reduced cost, the void between present physical coal cleaning capabilities and flue gas scrubbing for existing power plants.

B. Provide improved coal utilization alternatives for both repowering and new plant applications. These combine high levels of emission and effluent control with reduced costs and improved thermal efficiency.

As indicated by Figure 4, these objectives are geared to national, not just regional technology requirements. However, an important distinction should be recognized between these two objectives and the technologies they represent. The second has the potential to reduce the absolute cost and increase the productivity of power generation. The first objective can only limit the cost increase which would otherwise be imposed by more expensive retrofit controls.

Under objective A, the inefficiencies and costs of current flue gas desulfurization technology coupled with the uncertain possibility that existing plants may require retrofitting of emission controls leads to the need for additional, simplified emission control options. These range from improved physical coal cleaning to combustion modification, furnace sorbent injection, partial and dry scrubbing, and low NO_x combustion. No single one of these options will satisfy the widely varying conditions in the range of existing coal-fired utility and industrial power plants. As a group, however, they can reduce the cost and productivity limitations of emission control today. Depending on regulatory requirements, the United States market for such retrofittable emission control options could be as much as 170,000 MW during the 1990s alone.

Selection will depend on a number of variables including control requirements, cost and functional criteria such as plant design and space limitations. Functional criteria can be a particularly important constraint when considering retrofit to existing plants. Unlike new plants where the boiler and emission controls can be designed as an integrated unit, retrofit requires adaptation to a plant not designed for such modification. Nevertheless, they can become particularly valuable in the event emission control on existing high sulfur coal plants is required. The potential for 50-70% SO_2 reduction is attractive under these circumstances.

EPRI has examined a variety of emission reduction requirements in terms of the potential savings achievable through optimal use of this array of new retrofittable technologies. In each case, capital and annualized costs were reduced from 40% to 70%. Unfortunately, the legislative and regulatory proposals developed thus far in the United States fail to provide the flexibility necessary to fully implement these opportunities, thus effectively limiting utilities to either scrubbing or retiring the majority of their units. A requirement to apply current flue gas scrubbing technology to existing units would impose an additional cost of nearly $300/kW and would force many units into retirement at a time when their power generation capability will be increasingly important to the reliable supply and cost of electricity.

Objective B, the use of new coal utilization technologies such as atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC), and integrated gasification combined cycle (IGCC) has the potential to be more effective both in terms of environmental control capability and cost. These technologies combine emission control within the combustion or conversion process, rather than adding new process complexity. The result is both greater emission control efficiency and improved generation productivity to fundamentally resolve perceived conflicts between energy and the environment. As a result, they are a more effective use of national resources than additions of flue gas desulfurization systems to existing coal-fired capacity. This underscores the value of economic and regulatory incentives that emphasize prompt transition to these improved coal utilization options rather than diverting resources into "band-aid" retrofit efforts.

The key question which must be resolved before large scale application of these options can occur is proof of their long-term reliability under utility operating conditions. The EPRI program, therefore, stresses the development and demonstration of these options at sufficiently large scale to verify their commercial reliability. In the absence of broad government participation in these large, capital intensive projects, the burden of support falls today on the private sector.

The highly successful Cool-Water IGCC, and the three AFBC demonstration projects being led by the utility industry and EPRI provide effective models for these technology demonstration efforts necessary to accelerate clean coal technology. EPRI has been pleased to be a partner and catalyst for these projects and looks forward to continuing its cooperative efforts, where possible, to stimulate the prompt acceptance of improved technology. Unfortunately, EPRI is able to fund less than half the scope of its planned program at a time when needs are increasing dramatically as a result of the industry's successful development efforts.

The strategic environmental advantages of the new clean coal technologies relative to conventional wet scrubbing are also substantial. Proposed acid rain control legislation -- that would retrofit flue gas scrubbers on up to 100,000 MW of existing, high sulfur coal-fired generating capacity -- could cost the nation as much as $12 billion per year over the remaining life of the affected plants. A more effective alternative would be to accelerate new clean coal technologies that offer greater emission control efficiency and improved generation productivity.

Figure 5 indicates the impact on SO_2 emission trends of various control strategies. Encouraging the application of advanced clean coal technology such as fluidized bed combustion and gasification combined cycles for new plant and repowering applications achieves and, most importantly, sustains an increased downward trend in emissions while improving productivity. Proposed control strategies that focus on existing sources produce results which by comparison, rapidly diminish over time. If, for example, the $200 billion necessary to implement the scrubber retrofit strategy over the remaining life of the affected plants were instead invested on new plants using advanced clean coal technologies, it would provide about half of the new generating capacity the nation is likely to require during the next 30 years. Such an investment would provide superior environmental control, not only for sulfur oxides but also for nitrogen oxides and solid waste, while improving the productivity and cost of power generation.

Unfortunately, legislative proposals for acid rain do not typically emphasize clean coal technology; and as a result are likely to delay the use of these new technologies by forcing the industry to divert needed capital into retrofitting wet flue gas scrubbers as the only option which can be confidently retrofitted by the legislative deadlines. In the absence of an aggressive Clean Coal Technology demonstration program, conventional wet scrubbing remains the only control option available for most existing plants to meet the proposed emission reduction requirements. Any new regulatory requirements, if and when justified, should therefore emphasize flexibility and cost effectiveness if the more effective clean coal technology options are to be encouraged.

The restrictive requirements proposed to date are also likely to force, on economic grounds, the premature retirement of valuable generating capacity, particularly in the high sulfur coal using states. This will exacerbate the electric generation supply shortage expected in the later 1990s. The likely result will be a decrease in the quantity and reliability of electrical service. This would be coupled with a rise in electricity cost, likely forcing industry to relocate away from the affected regions to remain competitive.

Clean Coal Technology Status and Demonstration Requirements

Figure 6 indicates the general cost and performance envelope for Clean Coal Technology in terms of (a) commercially available options, specifically flue gas desulfurization and physical coal cleaning; (b) advanced, retrofittable technology now entering the demonstration phase; and (c) advanced, clean powerplant technology, such as fluidized bed combustion and coal gasification-combined cycles, for both new and repowered plant applications.

Figure 7 indicates the characteristic learning curve associated with the development and commercial deployment of new technology. Today, the various advanced clean coal technology options under consideration are completely developed and approaching first commercial service or demonstration. It is their "commercial demonstration" phase where the size and cost of the facility necessary to assure realistic operation is the greatest. This "conventional risk cost" then reduces over a series of additional installations until full commercial material is reached. It is recognition of this risk and the need to share in the cost of its resolution which defines the need for the National Clean Coal Technology Demonstration initiative.

Table 1 organizes the various advanced clean coal technologies into six general categories and summarizes their major risk factors which must be resolved through the demonstration process. The attached discussion further describes the status and demonstration requirements for each of these general categories including their technology subsets.

The response to DOE's November 1986 Phase II Request for Statements of Interest concerning Clean Coal Technology demonstration projects again affirmed these technical opportunities and the private sector commitment to their success. 137 expressions of interest were provided with potential, private sector, cost sharing exceeding $2 billion. This compares quite favorably with the 175 projects originally identified in February 1985, in response to the Phase I DOE Clean Coal Demonstration solicitation.

Table 2 categorizes these 137 submissions by technology. The number of retrofittable flue gas cleanup and coal preparation demonstrations is particularly noteworthy since neither of these categories was well represented in the projects selected by DOE during Phase I of the Clean Coal Demonstration Initiative.

As in Phase I, the nation's ability to realize these opportunities will depend on the policies used by the Administration and Congress. Based on the limited results of the Phase I Clean Coal Technology Demonstration initiative, the following modifications are recommended:

- The philosophy of project selection should reflect DOE's role as an expeditor of technology for use by the private sector. DOE will not be the user or purchaser of the commercial products resulting from this program. Selection and procurement procedures should better reflect this distinction.

- The information requirements for project proposals the PON should be substantially reduced. The previous requirement for full-scale environmental analysis should be dropped in favor of a site-specific analysis of environmental impacts. More latitude should also be given to proposers in estimating potential for commercial use. The fact that a project is proposed shows that interest exists not only by the host but its cosponsors who are typically the ultimate vendors.

- The selection criteria should reflect the importance of demonstrating technologies that can be applied on a retrofit basis to the existing generating capacity in the U.S. The criteria should emphasize retrofittability, cost-effectiveness ($/ton removed), and emission reduction potential. This importance remains largely unsatisfied for technologies which can span the gap between the available low removal efficiency SO_2 controls (such as existing coal cleaning) and high cost, high SO_2 removal technologies (such as wet scrubbing).

- Ambiguity concerning repayment of Federal assistance should be eliminated. In the past, this has discouraged participation since utility profits are established by regulatory bodies. It is important that future solicitation encourage stronger utility industry participation since this industry is by far the nation's largest user of coal and is fundamental to the nation's economy. It is also the industry through which the greatest environmental and productivity benefits can be realized by application of clean coal technologies.

- The Federal Government should take advantage of its unique opportunity to work more closely with the private sector in resolving the various constraints, often resulting from governmental action, on the use of innovative technology. In this context, cofunding is only one way in which DOE can help. DOE should also encourage, when opportunities arise, programs which could result in increased private sector R&D efforts and reduce the need for direct DOE involvement. For example, the state of Ohio has recently taken the initiative of funding clean coal technology demonstration programs in such a way that the industrial partners retain the commercial and managerial incentives. The state role is to promote demonstrations by sharing part of the cost and insuring a reasonable rate of return on the remainder by acceptance in the utility rate base. Taken a step further, this federal encouragement of favorable state action becomes even more important to the prompt commercial deployment of clean coal technology by the regulated electric utility industry. Particularly important are expedited permitting reviews, presumption of prudence, and prompt cost recovery.

- This underscores the need for an effective coordination mechanism between federal and state governments to develop cost and risk-sharing incentives in as effective manner as possible, including assured cofunding for multi-year demonstration programs. The establishment of this coordination mechanism, for example, could be encouraged by a conference of governors from coal utilizing and coal producing states along with the heads of affected federal agencies. An industry task force also needs to be established that is empowered to provide combined business and technical judgment, guidance, and direction for the DOE Clean Coal Technology program. Such a panel could provide valuable input to the DOE and Congress in the prioritization and acceleration of clean coal technology having important productivity and environmental potential.

Summary and Conclusions

1. The principle which guides clean coal technology development is that sustained environmental improvement can only be achieved when both emission and cost reduction are achieved concurrently, not pitted against each other. Clean Coal Technology thus provides a unique opportunity to concurrently satisfy two national goals: (a) continue the substantial progress made in emission control by resolving the conflicts between coal use and environmental protection and (b) meet the rapidly approaching electricity generating capacity challenge with reduced cost and increased productivity.

2. Demonstration efforts should be initiated promptly through joint industry/government sponsorship for improved repowering and new plant coal utilization methods, plus the array of cost effective, retrofittable emission control options. These are necessary to commercially realize the successful clean coal technology development efforts which have been underway for the past decade. The highly successful Cool Water integrated gasification combined cycle and the three atmospheric fludized bed demonstration projects being led by

the utility industry and EPRI provide effective models for these technology demonstration efforts necessary to accelerate clean coal technology.

3. The Phase I Clean Coal Technology Demonstration projects awarded by DOE in July 1986 will not be sufficient to meet the objectives of the Congressional Clean Coal Technology Initiative as defined in P. L. 99-190. Ample opportunities to satisfy these objectives have been identified, however, in the subsequent 137 responses to DOE's November 1986 Request for Statements of Interest concerning Clean Coal Technology Demonstrations.

4. The inflexibility of proposed legislation intended to further reduce emissions tends to discourage the application of innovative clean coal technology and limit freedom of choice. The result may be to substantially increase the cost of compliance and delay implementation of new clean coal generating capacity which combines emission control and cost reduction. The result will be eroded environmental quality and economic productivity, quite contrary to the expectations of the legislation.

5. The future for clean coal technology is now. Success depends on prompt, aggressive action by government and industry to both accelerate demonstration and remove impediments to prompt commercial application. EPRI is prepared to do its part in supporting these efforts.

FIGURE 1

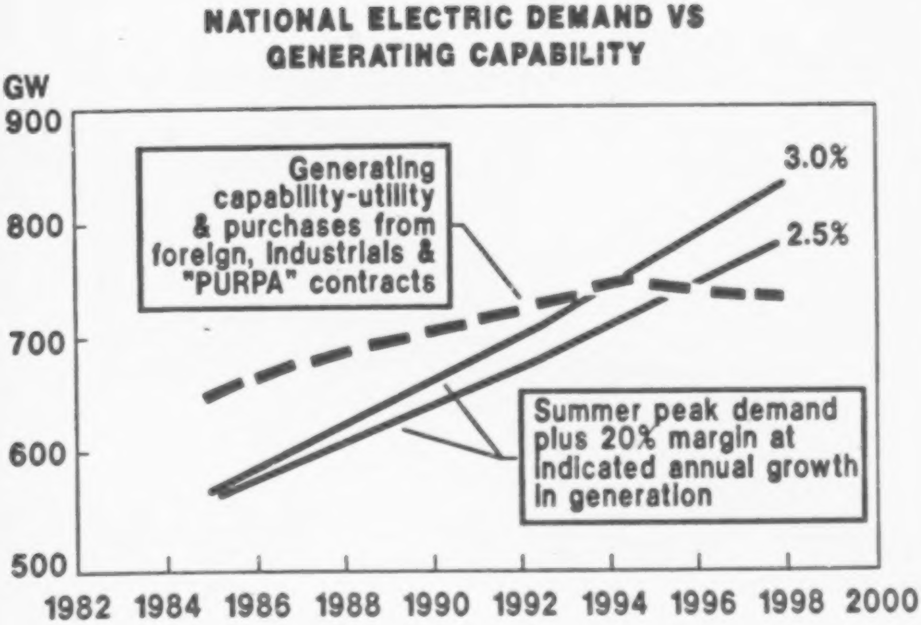

NATIONAL ELECTRIC DEMAND VS GENERATING CAPABILITY
GW
900
800
700
600
500
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
Generating capability-utility & purchases from foreign, industrials & "PURPA" contracts
3.0%
2.5%
Summer peak demand plus 20% margin at indicated annual growth in generation

FIGURE 2

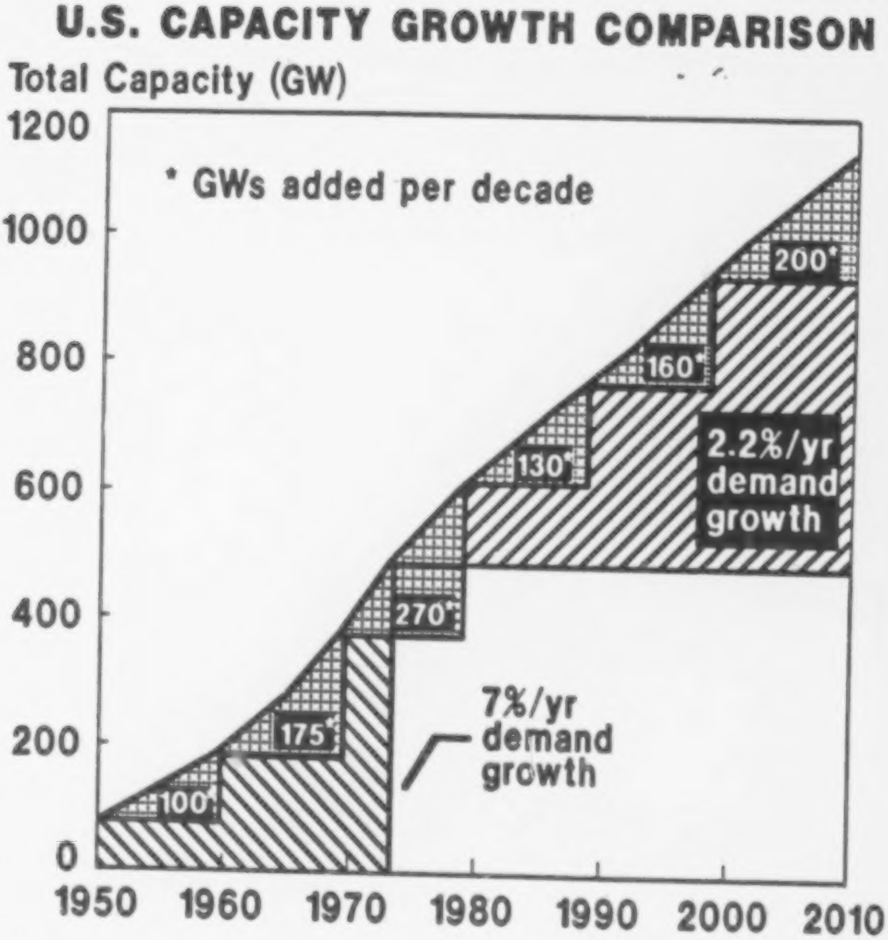

U.S. CAPACITY GROWTH COMPARISON
Total Capacity (GW)
1200
1000
800
600
400
200
0
* GWs added per decade
100*
175*
270*
130*
160*
200*
2.2%/yr demand growth
7%/yr demand growth
1950
1960
1970
1980
1990
2000
2010

FIGURE 3

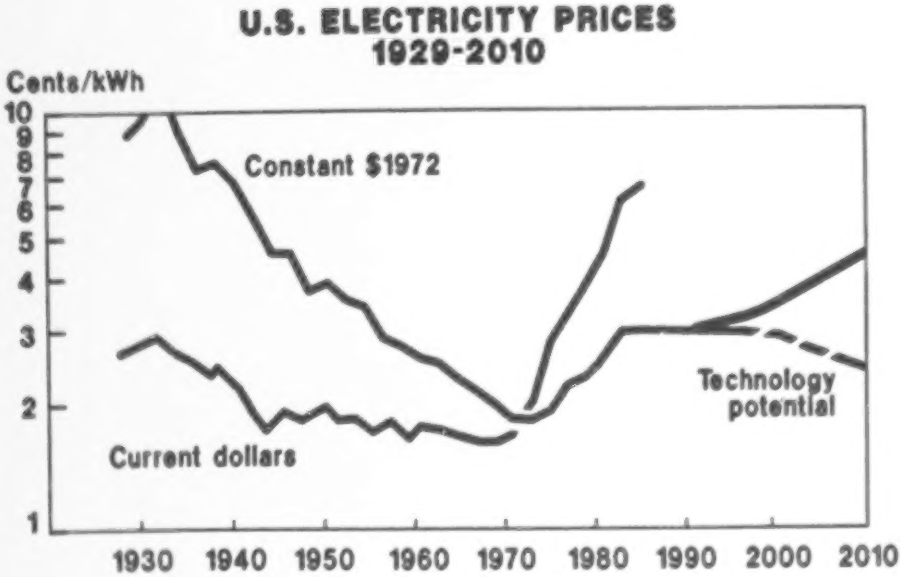

U.S. ELECTRICITY PRICES
1929-2010
Cents/kWh
10
9
8
7
6
5
4
3
2
1
Constant $1972
Current dollars
Technology potential
1930
1940
1950
1960
1970
1980
1990
2000
2010

FIGURE 4

CLEAN COAL TECHNOLOGY Application

	Midwest	E. Coast	West
New plant	3	2	1
Repower	1	1	2
Retrofit	1	1	3

1 High priority
2 Moderate priority
3 Low priority

Figure 5

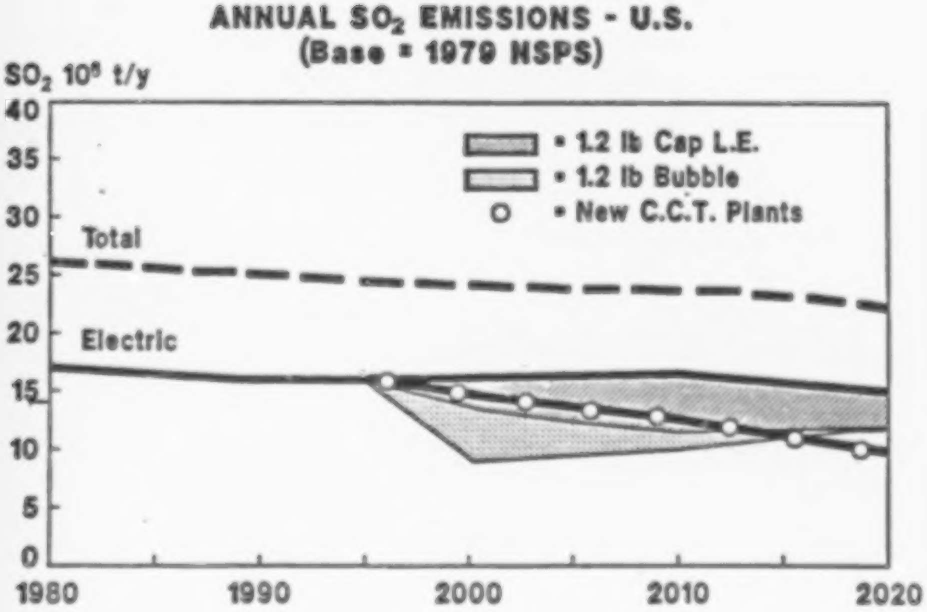

ANNUAL SO$_2$ EMISSIONS - U.S.
(Base = 1979 NSPS)
SO$_2$ 10^6 t/y
40
35
30
25
20
15
10
5
0
1980
1990
2000
2010
2020
Total
Electric
= 1.2 lb Cap L.E.
= 1.2 lb Bubble
= New C.C.T. Plants

Figure 6

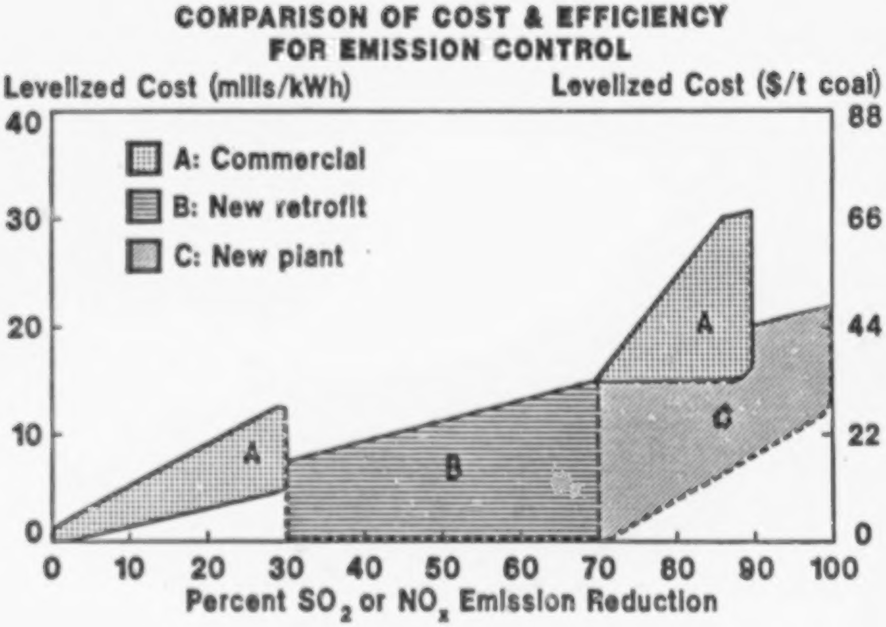
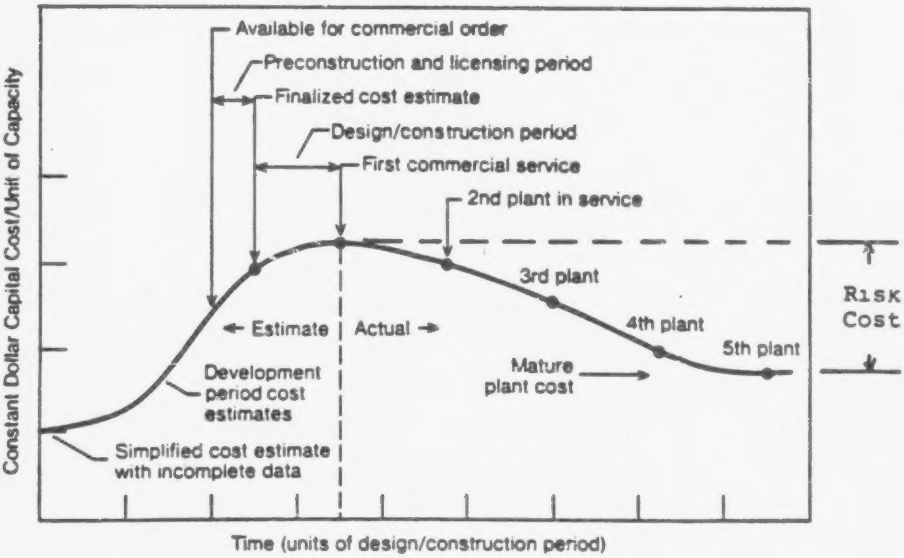

COMPARISON OF COST & EFFICIENCY
FOR EMISSION CONTROL
Levelized Cost (mills/kWh)
Levelized Cost ($/t coal)
40
30
20
10
0
88
66
44
22
0
A: Commercial
B: New retrofit
C: New plant
A
B
A
C
0
10
20
30
40
50
60
70
80
90
100
Percent SO2 or NOx Emission Reduction

Figure 7



Cost Learning Curve

TABLE 1
CLEAN COAL TECHNOLOGY APPLICATIONS AND RISKS

TECHNOLOGY	CAPITAL COST ($/KW)*	NET COST EFFECTIVENESS $/TON SO_2 OR NO_X REMOVED	APPLICABILITY		RISK FACTORS REQUIRING RESOLUTION
			RETROFIT	REPOWER/ NEW	
1. Coal Cleaning and Upgrading					
A. Advanced Physical Coal Cleaning	60-100	400- 600	X	X	• Degree of sulfur removal • Btu recovery • Increase in coal moisture • Economic agglomeration technology
B. Low Rank Coal Upgrading	60-120	-	X	X	• Capital cost of equipment • Btu recovery • Product quality
2. Wet FGD					
A. Advanced Conventional FGD	200-300	400- 600	X	X	• Capital costs of redundancy and materials • O&M cost savings through elimination of reheat
B. Advanced Regenerable FGD	300-400	500- 700	X	X	• Capital costs of materials and redundancy • O&M costs associated with membrane plugging, sorbent use
3. Dry SO_2 Control					
A. Furnace Sorbent Injection	50- 75	700- 900	X		• Boiler impacts • ESP Upgrade costs • Waste management
B. Duct Sorbent Injection	50-100	500-1000	X		• Duct deposition (calcium systems) • Baghouse performance (hybrid system) • Soluble wastes, NO_2 plume, sorbent cost and availability (sodium system) • Particulate control/humidification • Waste management

TECHNOLOGY	CAPITAL COST ($/KW)	NET COST EFFECTIVENESS $/TON SO_2 OR NO_x REMOVED	APPLICABILITY RETROFIT	APPLICABILITY REPOWER/ NEW	RISK FACTORS REQUIRING RESOLUTION
4. NO_x Control					
A. Low NO_x Combustion and Reburning	5- 35	100- 500	X	X	• Effects on carbon burnout, flame efficiency and stability, slagging and corrosion
B. Postcombustion	75-100	4000-8000	X	X	• O&M costs of catalyst replacement • Availability loss due to air heater cleaning
5. Fluidized Bed Combustion					
A. Atmospheric	600-1300[a]	0- 200[b]		X	• Capital and O&M costs of heat transfer surface and solids handling systems
B. Pressurized	800-1400[a]	0- 200[b]		X	• Capital costs as per AFBC • O&M costs of sorbent utilization and gas turbine maintenance
6. Integrated Gasification Combined Cycle	1000-1500[a]	200- 500[b]		X	• Capital costs of design conservatism • O&M costs of heat transfer fouling, refractory & sulfur recovery • Availability loss during startup

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* For an approximately 250 MW retrofit/repower on medium to high sulfur coal (2.5-4% sulfur).

[a] Total installation cost range reflects repower and new applications.

[b] Net SO_2/NO_x control cost effectiveness with credit for additional capacity and fuel savings.

TABLE 2

PROJECT SUBMISSIONS RECEIVED BY DOE CATEGORIZED BY TECHNOLOGY

TECHNOLOGY	NUMBER	TOTAL VALUE* ($X10^6)
FLUE GAS CLEANUP	52	524
FLUIDIZED BED COMBUSTION	15	611
SURFACE COAL GASIFICATION	10	1,190
COAL PREPARATION	29	665
COAL FIRED TURBINE	4	3
ADVANCED COMBUSTORS	11	160
ALTERNATIVE FUELS	4	133
FUEL CELLS	1	-
MHD	1	400
NON-TECHNOLOGY SPECIFIC	5	43
IRON AND STEEL PROCESSES	2	-
OTHER	3	8
TOTAL	137	3,737

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* 83 OF THE 137 RESPONSES INCLUDED COST ESTIMATES.

TABLE A-1
DRY SO_2 CONTROL
DUCT INJECTION

Process	Stage Development	Projects	Development Issues	
Duct Injection Sodium	Commercial	100 MW demo (R.D. Nixon/EPRI)		o Soluble waste o NO_2 plume o Sorbent cost/ availability in East
Duct Injection Calcium	Pilot (1-5 MW) Demo (~ 100 MW)	EPRI-Arapahoe DOE-Ohio Edison EPA-Edgewater EPRI-EPA-Richmond EPRI/Util.-Brayton Point W. Europe Demos	Humidification Particulate Control Waste Management	o Duct Deposition
In-Duct Spray Drying	Pilot (1-5 MW)	EPRI-Arapahoe DOE/Bechtel-Consumers DOE/GEESI-AEP		o Duct Deposition
HYPAS	Pilot (4 MW)	EPRI-HSTC		o Baghouse Performance
FSI	Demo (100 MW)	EPA/DOE-Edgewater EPRI/EPA-Richmond Canadian Utilities W. Europe Demos		o Boiler impacts o Reactive waste
CPI	Lab/pilot (25 MW) field	EPRI-Lab scale EPRI/DOE (proposal) Saskatchewan Power/EPRI		o Sorbent performance

TESTIMONY OF DR. FLYNT KENNEDY
BEFORE
SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
UNITED STATES SENATE
WASHINGTON, D.C.
MARCH 4, 1987

Good Morning. I am Flynt Kennedy, General Manager of Coal Research and Development for Consolidation Coal Company, a Du Pont subsidiary.

Since its inception in 1947, the research division of Consolidation Coal Company (Consol) has pursued a dedicated course to expand coal sales through the development of technology for the safe, economical, and environmentally acceptable production and utilization of coal. The efforts of 160 scientists, engineers, and support staff in Pennsylvania and West Virginia are focused on providing technology to overcome economic or environmental barriers to the maximum use of coal. Our research budget is about $15 million per year.

Many environmental issues related to the use of coal remain the appropriate subject of scientific inquiry and debate. Consol recognizes that these are important issues to the coal producer, the coal user, and ultimately to the energy consumer. For that reason, we are expending about two-thirds of our research effort directly or indirectly addressing environmental issues. Of particular emphasis is the development of cost-effective technology to reduce sulfur dioxide emissions from coal-fired electrical power generation.

Consol's lengthy experience in SO_2 technology development is instructive because it illustrates several important factors which must be considered in formulating and conducting a program for the commercialization of SO_2 abatement technology.

In the 1970's, Consol pioneered an advanced process for the removal of SO_2 from utility boiler flue gas. Known as the CONOSOX process, this technology had the advantage of producing a salable by-product rather than a disposable waste by regenerating the chemical reactant used for sulfur dioxide capture. Our goal was to develop one process that was clearly superior to existing commercial technology and would be suitable for a broad range of utility applications. However, because of its chemical complexity, the CONOSOX process costs grew to the extent that its further commercial development was discontinued.

What we gained from this experience was an appreciation of the need to promote and support the development of a menu of SO_2 compliance technologies so that at least one cost effective option is available to each coal user.

In 1984, Consol conducted the first successful large-scale test of Boiler Limestone Injection (BLI) which included LIMB, or Limestone Injected Multi-stage Burners as it is commonly called, with high-sulfur United States coal. This 15 MW industrial boiler demonstration at Martinsville, Virginia, showed that injecting limestone into the furnace is an effective means of achieving partial SO_2 removal (about 50%) without impairing boiler performance. During this program, Consol also tested a related process involving sorbent injection into the flue gas downstream of the boiler. Named the Coolside process because of the low temperatures at the point of sorbent injection, this technology proved capable of over 75% SO_2 removal at acceptable sorbent injection rates. Although Boiler Limestone Injection and Coolside cannot achieve the 90% or greater SO_2 removals of commercial Flue Gas Desulfurization (FGD) units (better known as scrubbers), they are low in capital cost, require less space for installation, and can be installed in a relatively short time. Therefore, they are attractive entrees on our menu for lower capital cost retrofit applications at older utility stations which might require partial SO_2 reduction for compliance.

During the Martinsville tests, Consol also pioneered the use of flue gas humidification, which maximizes SO_2 capture while minimizing the particulate emissions which result from sorbent injection.

To further the commercial development of these sorbent injection technologies, we have presented our results to utility, industrial and government audiences and will dedicate patents to the public domain. We have vigorously pursued opportunities for full-scale demonstrations and are prepared to commit technical and financial resources to such demonstrations. As a result, humidification and the Coolside process are included in an EPA-sponsored demonstration of a boiler sorbent injection process. The demonstration will be conducted using a 105 MW boiler at Ohio Edison's Edgewater Station, near Cleveland, and is scheduled for completion in 1989. Co-sponsors and participants include the State of Ohio, Ohio Edison Company, Consol, and the prime contractor, Babcock and Wilcox. Partial funding for this expanded, broad-based demonstration was provided by DOE under their Clean Coal Technology Program, and it is one of the nine projects included in Phase I.

Other developers are also advancing the state of retrofit technologies for partial SO_2 control. Bechtel, Dravo, General Electric, DOE and EPA, via funding and/or in-house programs, are involved in process development. We encourage and, in some cases, actively support these efforts which will increase the number of selections on the SO_2 abatement menu.

As we have developed and evaluated these new technologies, we began to realize that well-designed conventional wet FGD technology, currently in commercial use in this country, and advanced wet FGD processes, which are fully ready for commercial application, also have a prominent place on the menu. Although higher in capital cost than the emerging sorbent injection technologies, these wet FGD processes are lower in operating cost because of the more efficient use of the sorbent materials. This means that once an FGD unit is installed, power can be generated for the lowest incremental treating cost. Concerns about the reliability of these scrubber systems have been largely dispelled by the recent experience gained in this country and abroad. Therefore, wet FGD can be a technology of choice, even in retrofit situations, for those larger, base-loaded units for which the capital cost will be more than offset by low operating costs. We are working closely with utility customers to develop a demonstration project of advanced wet FGD technology as applied to high-sulfur coal for the anticipated second solicitation of Clean Coal Technology Funds.

Other clean coal technologies, such as atmospheric and pressurized fluidized bed combustors and integrated gasification/combined-cycle power generation, are at commercial or near-commercial stages of development. These technologies produce power with low levels of sulfur oxide emissions by integrating sulfur control into the process itself. However, they will find greater application in new power generation, or in repowering of existing facilities to add incremental power generation capability, rather than in retrofitting strictly for environmental compliance.

In summary, we have a growing menu of technologies which, if commercialized, can meet the short-term and long-term environmental compliance needs of the electrical generating industry. No single technology will fulfill every need, so we are justified in supporting the simultaneous advancement of a variety of processes, which includes the development of new technology and optimization of existing technology. Private industry is making a strong effort, on its own initiative and/or assisted by federal funds, to develop the technology needed. The interests of the fuel producer, power generator and energy consumer are best served by continuing to provide a variety of options to achieve the optimum balance between environmental needs and economic realities.

PERFORMANCE RESPONSE OF DRY SO_2 REMOVAL SYSTEM OF RIVERSIDE STATION

BY

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Prepared for Presentation at the
American Power Conference
43rd Annual Meeting
Chicago, Illinois

April 26 - 29, 1981

ABSTRACT

This paper discusses the history, design, start-up, and preliminary test results of the Joy Manufacturing/Niro Atomizer dry flue gas desulfurization system at Northern States Power's Riverside Generating Station. This 100 MW spray dryer absorption/baghouse demonstration plant is the first full-scale utility system to be put into operation utilizing lime as the scrubbing reagent. Initial process results as well as hardware performance are presented.

1. INTRODUCTION

The concept of dry flue gas desulfurization (FGD) by spray dryer absorption first received widespread attention in 1977 and has grown quickly in acceptance by the electric utility industry since that time. The first pilot plants in the United States were built in 1976 and 1977 and the economic utilization of lime as a reagent was first demonstrated on a pilot scale in 1978. The results and forecasts presented at the 1979 FGD Symposium in Las Vegas provided the utility industry with some of the earliest significant data regarding the applicability of dry scrubbing. By that time, several full scale systems had been bid and awarded and numerous pilot programs were underway.

Coincident with this effort was the review procedure for the New Source Performance Standards (NSPS) and a prevailing attitude that the NSPS should equitably encourage the use of emerging emission control technologies. The dry FGD work underway at that time gave support to the position that Western fuels could be burned and the resulting SO_2 removed economically to an acceptable level.

The NSPS did become promulgated in a way which encouraged the dry FGD process development. Although several independent economic evaluations were conducted which favored dry scrubbing, one concern in the utility industry was that a full scale system was not yet in operation. Joy Manufacturing Co. and Niro Atomizer, Inc. chose to build the first such system for demonstration and test purposes, simultaneously satisfying the needs of the industry and verifying the previously published pilot plant results.

This paper reviews the background of the first full scale dry FGD air quality control project, describes the system and the power plant it is coupled with, details the proposed test and demonstration plans, summarizes the successful start-up of the total system, and presents the first full scale process results to date.

2. HISTORY OF THE RIVERSIDE DEMONSTRATION FACILITY

The task that faced Joy and Niro was to find a site for a system large enough to be demonstratably acceptable to the utility industry. A boiler equivalent to at least 100 MW was considered to be a minimum size. Joy and Niro considered building a 100 MW demonstration module to operate in parallel with the existing wet scrubbers at the Northern States Power Company's (NSP) Sherburne County Generating Plant, Units 1 and 2. This received initial favorable consideration by NSP. However, due to the large size of the existing units (720 MW each) and therefore the expensive and cumbersome aspects of testing various fuels, Sherburne County, Units 1 and 2 were eliminated from further considersation. NSP, in turn, suggested an alternate location at their Riverside Station which offered advantages to all parties. In September of 1979, a contract was signed to build the demonstration plant at the Riverside Station, with Black & Veatch, consulting engineers (B&V), being selected as the consulting engineer for NSP.

3. DESCRIPTION OF THE RIVERSIDE DEMONSTRATION FACILITY

3.1 Description of the Riverside Generating Station, Boilers 6 and 7

Boilers 6 and 7 at the Riverside Steam Plant came on line in 1949 and 1950, respectively. The turbine-generators were identical 70 MW units supplied by General Electric and the steam generators are Babcock and Wilcox Co. pulverized coal, balanced draft boilers able to supply 640,000 lbs/hour, 900 psig main steam without reheat. Each boiler is followed by two parallel rotary air preheaters, Research-Cottrell wire-and-weight type electrostatic precipitators, and magnetic coupled induced draft fans. A separate brick-lined chimney serves each boiler.

In 1971, an accident damaged the Unit 7 turbine-generator and it was subsequently removed from service. At approximately the same time, the 400 psi boilers, Units 1 and 2, were retired, due to the cost of emission control requirements. To replace the retired boilers, the Unit 6 and 7 boilers' main steam headers were combined to supply steam to the #6 turbine and the two 400 psi turbines, through a pressure reducing station, for a total generation capability of 110 MW. The boiler's 6 and 7 steam and air/flue gas flows are shown in Figure 3.1.

The design fuel for the boilers is a 10,800 Btu/lb Illinois coal with a nominal 3.5% sulfur content. Due to environmental regulations, the boilers now burn a blend of 88% Western coal and 12% petroleum coke. The change in fuels allowed the station to operate within the limits of Minnesota's sulfur dioxide emission regulations, but the increased resistivity of the fly ash reduced the particulate collection efficiency of the precipitators. This required NSP to derate the boilers significantly to meet the state's 20% stack opacity limit. The derated condition of Boilers 6 and 7 limited the main steam output to 250,000 to 275,000 lbs/hour per boiler, approximately 55 MW total. This has been the operating condition of the plant since 1973, until the start-up of the Joy Baghouse.

3.2 Description of the Air Quality Control System at Riverside

The major components of the Air Quality Control System (AQCS) at Riverside are the spray dryer absorber (SDA) module, the reverse air baghouse, the two-speed ID fans, the lime handling, slaking, and feed preparation system, the discharge material handling system, and the electrical, instrumentation, and computer control package.

The spray dryer absorber module and the single rotary atomizer are both the largest of their kind in the world, and are identical to those being furnished by Niro for several other projects now in design and construction. The design gas flow is approximately 500,000 ACFM, but the Riverside installation permits testing to 25% over this rating.

The reverse air baghouse will be the first full scale unit in the utility industry to be operated consistently at temperatures as low as 10°C (18°F) above adiabatic saturation. The design is similar to that supplied by Joy for other utility installations, both for normal air heater outlet temperatures, and for the dry FGD projects now in design and construction.

The lime handling, slaking, and feed preparation system incorporates the features of parallel slaking trains, (either through a ball mill or an attrition slaker), two recycle feed points (from either the absorber or the baghouse), and other components, including pumps, tanks, agitators, and conveyors similarly sized as those for Joy/Niro FGD projects now in design and construction.

The discharge material handling system includes both drag link type chain conveyors and dense phase pneumatic handling. These offer the advantage of continuous hopper evacuation and low energy consumption.

Figure 3.2 is a simplified flow diagram showing the major components and the flow paths of the process. Considerable flexibility regarding gas flow capabilities have been designed into the plant and either of the two boilers can be tied into the spray dryer. Outlet gas from the spray dryer can be directed to either the baghouse or the Unit 7 precipitators. The new ID fans draw suction on the baghouse while the existing ID fans service the precipitators. The existing stacks are still in use.

The lime handling, slaking, and feed preparation system receives pebble lime, unloaded pneumatically from trucks, into a 170 ton storage silo. The lime is mechanically conveyed and fed gravimetrically into either the ball mill or the attrition slaker. In either case, a spiral classifier or vibrating screen classifies the lime slurry to allow only fine particles to be introduced to the mix tank. Recycle material from either the absorber, the baghouse, or both, is fed gravimetrically, along with make-up water, into the mix tank. The three inputs comprise the slurry feed which is sent through two screens, kept in suspension by agitation and continuous pumping loops, and flows by gravity to the atomizer.

The drying and most of the SO_2 removal take place in the absorber chamber. Dried recycle material, newly formed calcium sulfate and calcium sulfite and fly ash are removed from both the absorber and baghouse. The drag link conveyors in series with the dense phase pneumatic conveying systems send the dried material to either the recycle bins or the disposal silo. The equipment at the disposal silo is identical to that presently in use at the Riverside Generating Station for fly ash handling.

The control of the system components is being accomplished by three independent systems. The new ID fan controls have been integrated into the existing Boilers 6 and 7 draft controls. The SDA, lime handling, slaking, process feed preparation, and material discharge systems are computer controlled from a terminal in the existing control room. The baghouse sequence controller and interlocks are an independent microprocessor unit.

4. PROGRAM OBJECTIVES

In addition to the general demonstration aspect of the project, NSP, B&V, Joy, and Niro each have specific test objectives that are to be realized from Riverside. These are:

1. Demonstration of operation with various fuels, including low sulfur Western coal and higher sulfur Eastern or Mid-Western coal.

2. Confirming of the scale-up factors from pilot to full-scale operation.
3. Optimization of energy and reagent consumption.
4. Demonstration of particulate and SO_2 removal capabilities with either a baghouse or an electrostatic precipitator.
5. Determining the characteristics of the dry FGD waste product with respect to disposal and utilization.
6. Demonstration of the system's operational flexibility, including turndown, start-up, shutdown, and normal operation.
7. Demonstration of operation with various fabric filter media.
8. Characterization of the system operation and maintenance costs.
9. The establishment of system availability and reliability data.
10. Demonstration of long-term low-temperature operation.
11. Confirming the sensitivity of various operating parameters in a full-scale system.
12. The development of operating and maintenance procedures.
13. The training of power plant operators.

5. REVIEW OF PLANT START-UP AND INITIAL OPERATION

The complete start-up of the Riverside Demonstration Plant required a coordinated effort by the four parties; NSP, B&V, Joy, and Niro. Each party was responsible for one or more key subsystems, which had to be integrated into a total system start-up. The schedule for when each subsystem was started up and operated initially was determined by three factors. These were:

1. Individual engineering/construction lead times.

2. The interest in operating a system or component group independent of the total system. For instance, key test data, such as SDA pressure drop, proof of SO_2 absorption, and determination of the baghouse emission level could all be demonstrated prior to full system operation without significantly affecting the completion schedule.

3. The final date when all systems were to be operable. Testing, fabrication delays, and construction schedule slippages were permitted only to the extent that the final system completion date was not significantly altered.

Initial start-up was in November, 1980. At that time, all subsystems required to operate the SDA in combination with the existing electrostatic precipitator (ESP) were checked out and initially run in a non-process mode. Some of the highlights of this period included the first flue gas through the SDA, the first water evaporation run and the operation of the process feed system with only water. By the end of November, sufficient checkout had been accomplished to permit preliminary SDA-ESP operation and test work.

Between early December, 1980 and mid-January, 1981, two coincident activities took place. The SDA-ESP system was in a preliminary operation mode and the new ID fans and baghouse were in final checkout.

The important points associated with the SDA-ESP preliminary operation were the first ball mill lime slaking and consequent SO_2 absorption in mid-December, 1980, the first introduction of recycle material and therefore, the first medium level solids operation in early January, and by mid-January, 1981, the achievement of sufficiently stable SDA-ESP operation to declare the lime handling, slaking, and process feed preparation, atomizer, and SDA discharge systems operational for test purposes.

The new ID fans and baghouse were checked out during this time. Special attention was paid to the boiler draft controls and baghouse leak testing. The boiler draft controls required extra efforts due to complications introduced by retrofitting the two boilers into one draft system and the degree of operational flexibility desired in the power plant system that now included two boilers, three turbines, three dust collectors, an SO_2 absorption chamber, six ID fans, and four FD fans.

The baghouse leak testing included two key areas of concern. The first was the potential casing leakages from either the exterior to the interior or from the "dirty" side to the "clean" side. To accomplish this leak check, a centrifugal fan was used to pressurize the entire baghouse. The second key area was the valve system. A considerable effort was made to insure correct seating of the outlet, reverse air, and bypass valves. The extra effort in these areas has resulted in low opacity and small temperature drops.

By mid-January, 1981, the new ID fans and baghouse were brought into service without the SDA in operation. This period lasted through late February, 1981, while the system was first run with one new fan, then with both fans until the boiler draft control system was adjusted. The baghouse, with no precoat, experienced 300°F temperatures with the one fan situation and 340°F temperatures when full load was achieved. At the conclusion of the period, full load baghouse performance testing was accomplished. Results of the tests showed negligible ΔT across the SDA chamber (which was acting only as a bypass duct), a small ΔT across the the baghouse, stack opacities of less than 5% for the Riverside stack diameter, and an outlet mass loading of less than 0.03 lb/mmBtu.

One step remained prior to the total system start-up. The control system for the SDA and process feed preparation systems required a short period of final checkout. Beginning in late February and carrying through early March, the SDA again operated with the ESP to perform the final tuning of the analog and computer control systems.

Coincident with these efforts, more SDA-ESP test and operational data was gathered which further demonstrated hardware and process capabilities. Of note during the brief period were the SDA operation at 18°F approach to adiabatic saturation, demonstration of high SO_2 absorptions, and consistently high solids feed operation.

On March 12, 1981, the entire new system was run for the first time; SDA, baghouse, and new ID fans. Unfortunately, the week following that date was marred by both turbine and boiler problems resulting in limited operation. But, by March 19, 1981, the entire system was again in operation with the load increasing as the plant repair work was being completed. By March 21, 1981, the system was into SDA-baghouse parametric testing at full load. Since that time, nearly all the key test parameters have demonstrated at several levels.

6. RESULTS TO DATE

6.1 Hardware and Subsystem Performance

The project has only been operational for a few months, but most of the major hardware and subsystem questions have been answered. Most of the problems encountered have been start-up or construction related, without requiring significant design or engineering changes. A brief discussion of how each major subsystem has performed under the wide range of operating conditions experienced thus far follows.

The atomizer and spray dryer absorber have been run at a wide range of gas flows and temperatures, both inlet and outlet. Two different atomizer speeds have been used and in both cases, there have been no material buildups in the chamber, and the discharge material has remained dry and free-flowing. Also, the atomizer and motor have operated at the low and high power ranges without problems.

The gas disperser system has provided adequate mixing of flue gas and atomized feed at all load conditions. Of particular initial concern was the effect of low load operation on both flue gas mixing and particulate entrainment. However, the results to date indicate no dust settling in disperser internals at low loads and complete flue gas mixing at all loads.

The baghouse has also experienced a wide range of gas conditions, ranging from full load and high temperatures to low load and low temperatures. The baghouse has operated long periods at various combinations of load and temperature with stable pressure drop conditions, no evidence of corrosion, low heat loss, no hopper evacuation problems, and no signs of bag blinding.

With the exception of a few start-up problems, the lime handling, slaking and process feed preparation system has performed well. The equipment is typical heavy industrial equipment, such as screens, tanks, agitators, ball mill, classifier, attrition slaker, conveyors, and pumps. This equipment is somewhat smaller than comparable components in the main power plant; i.e. the ball mill has only a 4 ton per hour capacity, the tanks are 5000 gallons each, and the pumps rated at approximately 200 GPM. The combination of smaller sized slurry handling equipment and similarity to existing power plant equipment has made it easy to adapt these components to the normal operation practices. Even high solids operation and frequent start-ups and shutdowns have caused few problems.

There are some components which are somewhat new to the power industry or are being used in a slightly different fashion. For example, the use of weigh belts to handle fly ash has required some extra start-up work and operator training, but in a relatively short period, fly ash dusting and flooding problems were resolved and the operators have become familiar with a properly operating system.

The material discharge system has required more start-up effort than any other system, but the difficulties have been traceable to a faulty material specification on the SDA chain conveyor and several legs of temporary dense phase pneumatic piping. As of early April, 1981, a new conveyor of harder material had been installed and all temporary discharge piping removed. The two fixes have reduced the material handling problems to a minimum.

The last major component to be discussed is the control system. Combining three independent control systems required considerable coordination and some new boiler draft and ID fan control procedures. The end result is an integrated working system which requires some manual attention at start-up and shutdown to insure the correct sequence of events, but during normal operation needs little more effort than was previously given to the old boiler system.

6.2 Total System Performance

As discussed in the previous section, the initial operation period of the project had some start-up problems, but there have been no conceptual problems noted and very few design changes required. The situation is noteworthy considering the typical operating mode for the generating station; that is, as a peaking plant. Boilers 6 and 7 are often started and brought to near full load on a daily basis. This type of operation increased the importance of resolving all problems, regardless of significance, in an effort to make the dry FGD system as flexible as the rest of the plant.

Currently, procedures have been developed so that two operators can bring the system to stable operation, from a standby mode within 2 hours. Once at stable operation, the AQCS controls follow normal boiler swings easily and require only 1 to 1-1/2 shift operators, even in a test condition where the outside operator's duties are expanded to include some material sampling and data taking.

NSP is operating the baghouse and fan control without Joy/Niro supervision while Niro provides an advisor for the computer control of the SDA and associated subsystems. The rapid acceptance of the new, and different types of control systems is a good indication that the system and control logic are easily understood and the hardware and process problems have been minimized.

6.3 Process Results

6.3.1 Performance as a Spray Drying System

Experience in spray drying technology has established that the residual moisture in the discharge material from a spray dryer is a function of how well the drying operation is accomplished. Dry FGD is first a spray drying operation and within that industry, the importance of gas residence time combined with the proper spray/flue gas mixing and the degree of atomization have been recognized as important design parameters.

For optimal dry scrubber operation, Niro has advocated the compound gas disperser, high atomization of high solids slurries, and 10-12 seconds flue gas residence time in the SDA chamber. Figure 6.1 shows the residual moisture in the product from the SDA at Riverside as a function of ΔT from the adiabatic saturation temperature. Up to 7% residual moisture in the spray dryer discharge has been shown to be dry, free flowing and easy to handle. From the figure, it can be seen that if the atomization is too coarse, it will not be possible to operate the dryer as close to adiabatic saturation as is desired. Also, a shorter flue gas residence time will result in a moister product. Additionally, taking into consideration the possible variations in inlet temperature and gas flow, it is important that adequate gas mixing is accomplished to avoid a moist product or internal wall deposits.

6.3.2 Performance as an SO_2 Absorption System

Tests with the spray dryer absorber and electrostatic precipitator have been run at low gas flows since only the boiler 7 ESP can be combined with the SDA. As can be seen on Table 6.1, high SO_2 removal can be achieved with the SDA-ESP combination.

The SDA-baghouse combination has been run through an initial series of parametric tests, and the results have confirmed the SO_2 absorption capabilities of the full-scale dry scrubber. An extract of some of the parametric test results is shown in Table 6.2. The lime stoichiometry is in line with the results achieved during earlier pilot plant testing.

The SDA outlet temperature has been shown on pilot scale to have a major influence on the system SO_2 removal capabilities, regardless of the particulate collection device. This same effect has been demonstrated on the full scale system.

6.3.3 Performance as a Particulate Collection System

The baghouse particulate collection performance data to date has all been within guaranteed limits. Consistent emission levels of 0.03 lb/mmBtu or less have been measured, resulting in stack opacities of less than 5% for the Riverside stack diameter.

The baghouse pressure drop values are somewhat preliminary, due to the daily load swings, but still well within expected values.

Of major concern initially was the temperature drop across the baghouse, especially at low flows when operating close to the dew point. However, only a small temperature drop has been measured since initial operation.

6.3.4 Scale-up Correlations From Pilot Scale Data

Before the start-up of the Riverside dry scrubber, fly ash from Boilers 6 and 7 was shipped to Niro's permanent in-house pilot plant in Copenhagen. In this pilot plant, the site specific conditions at the Riverside station were simulated and a series of SO_2 absorption and particulate removal tests, with recycling of product, were performed. The results of the pilot tests are shown in Figures 6.2 and 6.3 as the solid lines. Actual full scale AQCS test results at Riverside are shown for comparison. As can be seen, full scale performance results correlate well with the results from pilot testing.

7. PROJECT SUMMARY TO DATE

The AQCS demonstration project at the Riverside Generating Station is now into a full testing and demonstration mode. This has been accomplished in the following steps: (1) start construction in September, 1979; (2) initial start-up in November, 1980; (3) completion of the construction effort in January, 1981; (4) completion of the start-up effort in early March, 1981, and (5) completion of the preliminary test phase by late March, 1981.

In conjunction with the beginning of the full scale testing and demonstration, the entire system is now in the process of turnover. NSP is preparing to accept the system for integration into the normal plant maintenance and operation activities by mid-May, 1981.

Plans have been made to conduct tests through the end of 1981, including short and long term tests, to evaluate low and higher sulfur coals, baghouse and electrostatic precipitator operation, and the full range of key process variables. Beyond 1981, the test and demonstration plans are not yet fixed and are subject to NSP, B&V, Joy, and Niro, and industrywide areas of of interest.

8. CONCLUSION

This paper has summarized the project development, test program objectives, key test results to date, and plans for the near future. In the presentation of the above, it can be seen that many of the major objectives of the program have already been realized. The project is the first full-size utility lime-based system that is complete and operable. The operation and test information to date indicates a good correlation with pilot plant test results, implying a sound design base. From NSP's standpoint, the completion of the baghouse results in an upgrading of the boilers 6 and 7 particulate control equipment and the opportunity to evaluate a full-scale dry FGD-AQCS system in a power plant environment.

The test plans, discussed in the previous section, give an idea of how NSP, B&V, Joy, and Niro intend to pursue the future evaluation of the AQCS. Within the next year, written information is scheduled to be published several more times, and site tours are planned for representatives from utility, industry, architect engineering, and many other business and governmental groups worldwide. The goal is to demonstrate the process sufficiently so it can be considered by all concerns as a reliable, economic, and proven system for power plant pollution control.

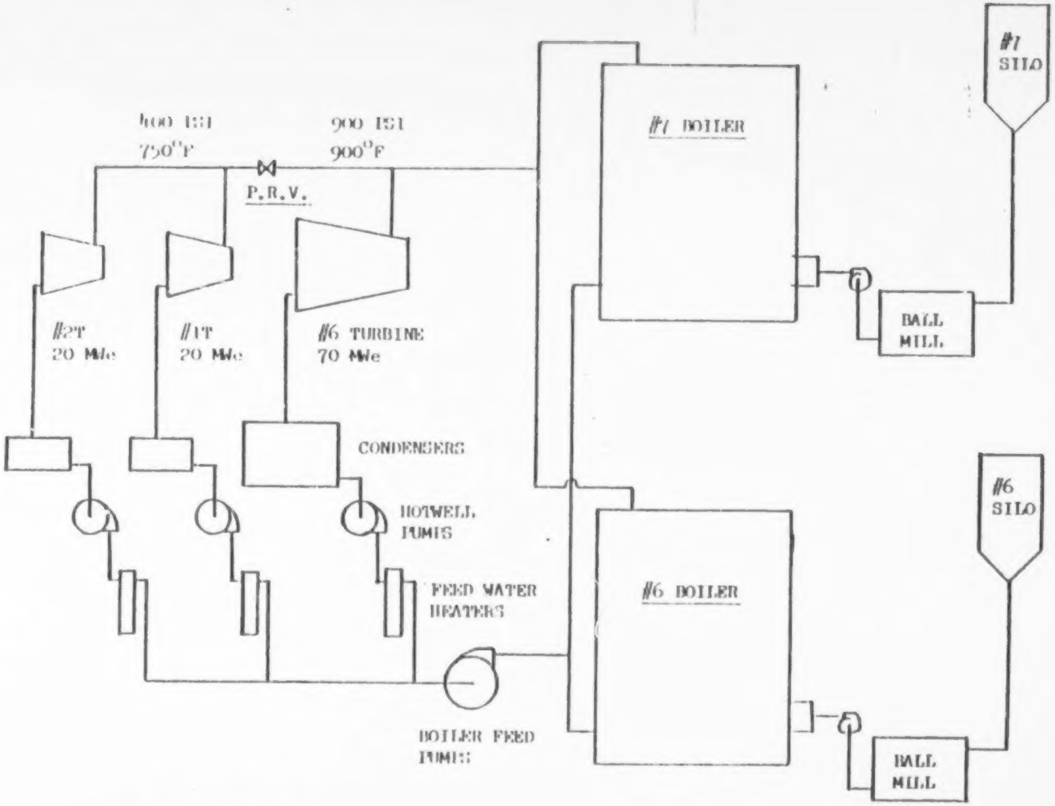
References

1. "The Riverside Station Dry Scrubbing System", Gary W. Gunther, James A. Meyler, Svend Keis Hansen; published at EPA Symposium on Flue Gas Desulfurization; Houston, Texas, October 28-31, 1980.

2. "Dry SO_2 Absorption and Particulate Control at Riverside Station"; B. Brown, J. A. Meyler; presented at EPA Third Symposium on the Transfer and Utilization of Particulate Control Technology; Orlando; Florida, March 9-12, 1981.

FIGURE 3.1

FIGURE : FUEL AND STEAM FLOWS


400 PSI
750°F
900 PSI
900°F
P.R.V.
#2T
20 MWe
#1T
20 MWe
#6 TURBINE
70 MWe
CONDENSERS
HOTWELL
PUMPS
FEED WATER
HEATERS
BOILER FEED
PUMPS
#1 BOILER
#6 BOILER
#1
SILO
#6
SILO
BALL
MILL
BALL
MILL

Flow Diagram — Riverside Dry Scrubbing System

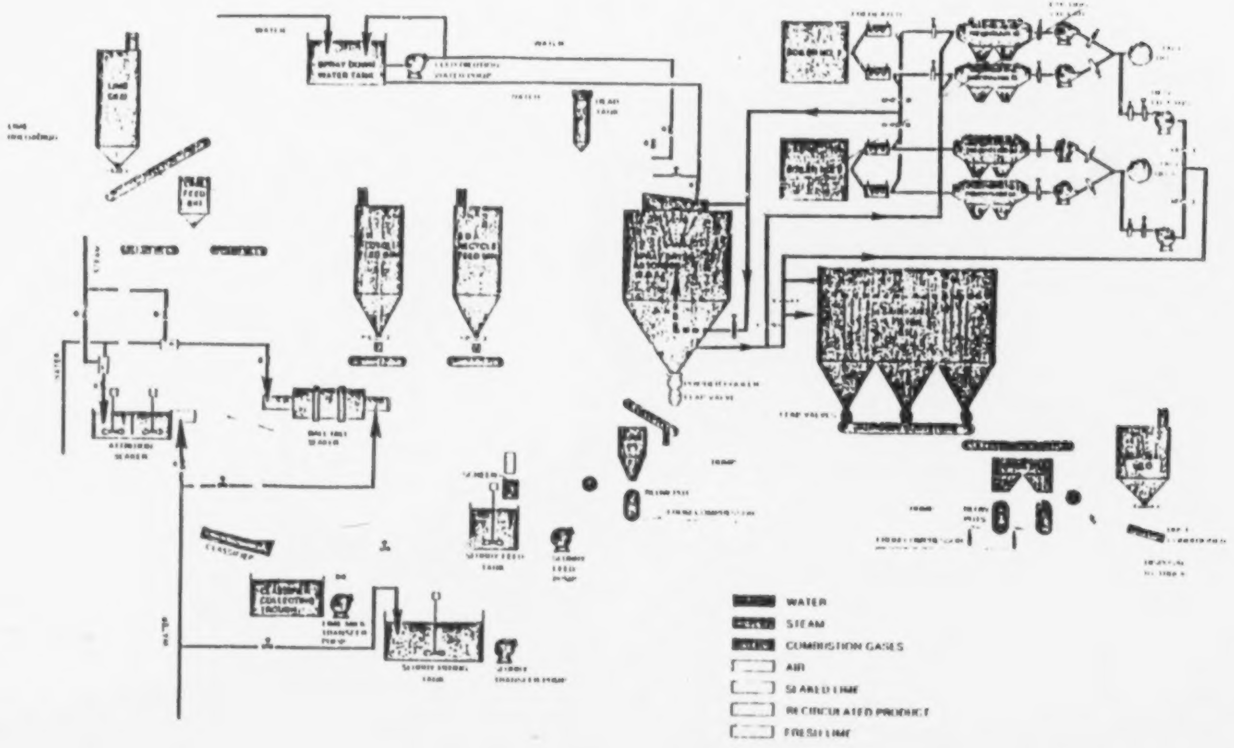

WATER
SPRAY DRYER WATER TANK
WATER
LIME SILO
FEED BIN
RECYCLE FEED BIN
WATER
STEAM
COMBUSTION GASES
AIR
SLAKED LIME
RECIRCULATED PRODUCT
FRESH LIME

FIGURE 6.1

RESIDUAL MOISTURE IN SPRAY DRYER ABSORBER PRODUCT VS. APPROACH TO SATURATION AND DEGREE OF ATOMIZATION

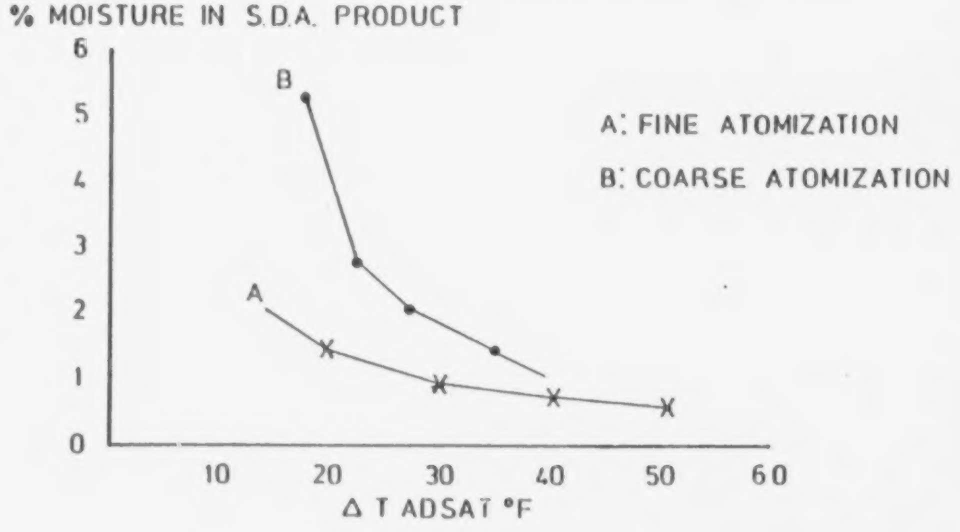


FIGURE 6.2

PERFORMANCE OF RIVERSIDE DRY SCRUBBER
COMPARED WITH PILOT PLANT DATA

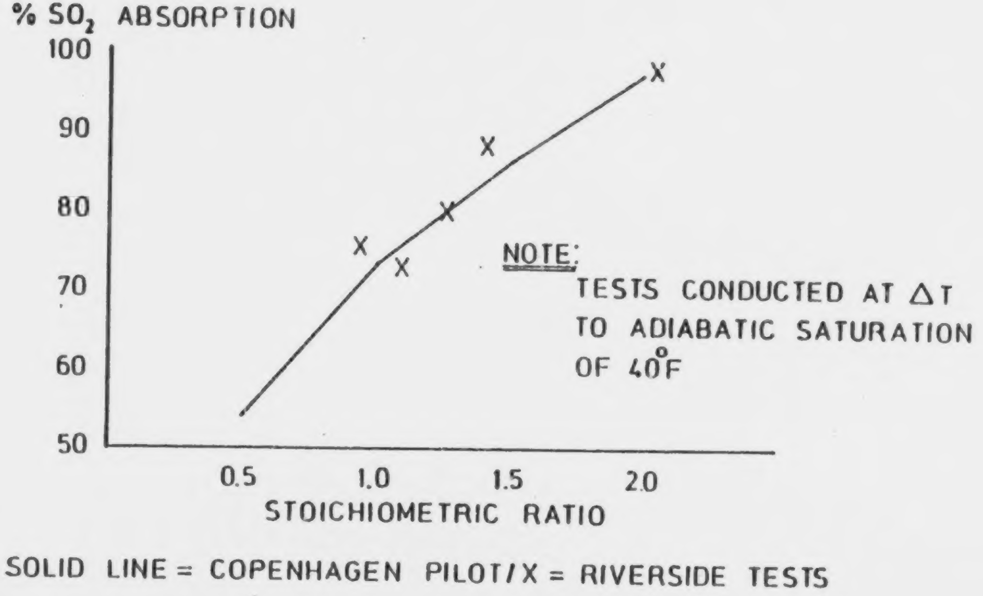
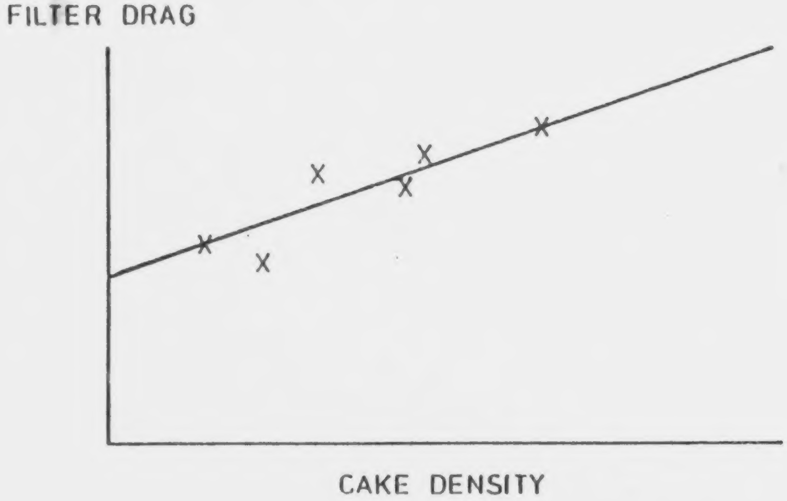


FIGURE 6.3

PERFORMANCE OF RIVERSIDE BAGHOUSE COMPARED WITH PILOT PLANT DATA



SOLID LINE = COPENHAGEN PILOT / X = RIVERSIDE TESTS

TABLE 6.1

PERFORMANCE OF RIVERSIDE DRY SCRUBBER, SPRAY DRYER ABSORBER AND ELECTROSTATIC PRECIPITATOR

GAS FLOW, ACFM	235,000	134,000
TEMPERATURES:		
SDA INLET °F	351	315
SDA OUTLET °F	175	140
ΔT AD.SAT. °F	47	18
GAS CONCENTRATIONS:		
SO_2 SDA IN PPM	1147	963
SO_2 ESP OUT PPM	356	120
SO_2 REMOVAL	69%	88%
STOICHIOMETRIC RATIO	<1.9	<1.8

TABLE 6.2

PERFORMANCE OF RIVERSIDE DRY SCRUBBER, SPRAY DRYER ABSORBER AND BAGHOUSE				
GAS FLOW, ACFM	367,000	504,000	347,000	362,000
TEMPERATURES:				
SDA INLET °F	295	328	317	310
SDA OUTLET °F	155	160	142	144
ΔT AD. SAT. °F	35	35	18	22
GAS CONCENTRATION				
SO_2 SDA IN PPM	839	858	843	893
SO_2 BH OUT PPM	188	82	49	166
% SO_2 REMOVAL	77%	90%	94%	81%
STOICHIOMETRIC RATIO	<1.3	<1.8	<1.4	<1.2

TABLE 4. FLUE GAS MASS LOADING SUMMARY

Sampling Location	Mass Loading, gr/dscf	
	Low Sulfur Tests	High Sulfur Tests
Spray Dryer Inlet	3.2 to 4.1	2.8 to 4.1
Spray Dryer Outlet	11.0 to 13.8	14.9 to 17.2
Fabric Filter Outlet	0.001 to 0.003	0.001 to 0.008

SULFURIC ACID MEASUREMENT RESULTS

Flue gas sulfuric acid concentration measurements were also conducted. For the low sulfur tests, no measurable sulfuric acid levels were detected at either the spray dryer inlet or fabric filter outlet. The inability to measure sulfuric acid at the dryer inlet is apparently related to the alkaline nature of the Sarpy Creek coal ash. It is not clear whether the alkaline ash removes all sulfuric acid upstream of the spray dryer, or whether any sulfuric acid present is removed on the ash collected on the heated filter in the sampling train. At the outlet of the fabric filter though, it is clear that no sulfuric acid is present. Measurements could not be made at the spray dryer outlet due to the high grain loading at that point, as the upstream filters tended to plug before an appreciable amount of flue gas could be sampled.

Measureable levels of sulfuric acid were found during the high sulfur test periods. Spray dryer inlet values were measured at 2 to 6 ppm SO_3. Fabric filter outlet values varied from 0.1 to 0.5 ppm. On a limited number of days where the spray dryer inlet and fabric filter outlet SO_3 concentrations were measured simultaneously, removal efficiencies of 90 percent or better across the system were indicated.

SUMMARY AND CONCLUSIONS

Based on preliminary data reduction for the 3-month test program on the NSP Riverside dry FGD system, the following conclusions are apparent:

- In general, the Riverside system ran quite well. None of the problems anticipated for spray dryer systems, such as rotary atomizer wheel pluggage, buildup of wet solids on dryer vessel walls, or wetting of fabric filter bag surfaces during upset conditions, were observed.

- Some problem areas at Riverside appear to be potential sources of problems on other similar dry FGD systems. These include typical problems with mixing and pumping slurries with a high solids content, solids handling equipment which requires continual maintenance, and sometimes inadequate atomizer protection during upset conditions.

- At sulfur levels up to a nominal 3.5 percent, high SO_2 removal efficiencies (90 percent) were readily achievable in the relatively short-term periods of this program. For the low sulfur Sarpy Creek coal/coke mixture, substoichiometric amounts of lime were required even at 90 percent SO_2 removal. This was attributed to the alkaline nature of the Sarpy Creek coal ash. For the high sulfur Illinois coal, 90 percent SO_2 removal required reagent ratios of approximately 1.3 to 1.4 moles lime per mole of inlet SO_2.

- Calcium chloride addition to the atomizer feed slurry to achieve chloride levels of approximately 1 percent in the fabric filter solids catch appeared to be successful in promoting lime utilization. For the high sulfur tests, the lime reagent ratio to achieve 90 percent SO_2 removal was reduced from 1.3 to 1.4 down to a range of 0.9 to 1.1 moles lime per mole of inlet SO_2. This chloride level would correspond to 0.3 percent chloride in a nominal 3.5 percent sulfur coal. Even for a low chloride, high sulfur coal, high chloride levels achieved through calcium chloride addition appear to be cost effective for reducing lime consumption.

- Particulate control efficiencies were high throughout the test program, maintaining outlet grain loadings well below required levels. In spite of baghouse operation within 18°F of the adiabatic saturation temperature and very high baghouse inlet grain loadings, no bag-fabric-related problems were observed and flange-to-flange pressure drop remained acceptably low.

- Based on a limited number of simultaneous measurements during the high sulfur test periods, sulfuric acid removal levels of 90 percent or greater were observed.

EMISSION REDUCTION, CAPACITY INCREASE AND LIFE EXTENSION THROUGH ATMOSPHERIC FLUIDIZIED BED COMBUSTION (AFBC) RETROFIT

by

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ABSTRACT

A 125 MW Atmospheric Fluidized Bed Combustion (AFBC) boiler retrofit firing western coal in a limestone bed is scheduled for operation in early 1986 by Northern States Power Company (NSP) at the Black Dog Generating Plant.

A technical and cost effective basis for responding to the acid rain issue in the upper Midwest is expected to be provided through the conversion of Unit 2 at NSP's Black Dog Plant from pulverized coal to AFBC operation. The Electric Power Research Institute (EPRI) has reported that over 200 units with a total capacity in excess of 20,000 MW built between 1945 and 1965 are potential candidates for conversion to AFBC. The 30-year-old Black Dog unit is located about 15 miles south of downtown Minneapolis, Minnesota.

Technical and economic feasibility studies, partially funded by EPRI, were completed in 1983 by Stone & Webster Engineering Corporation (SWEC) in conjunction with three of the major boiler manufacturers, and the project was authorized by the NSP Board of Directors in the 1984 budget. A demonstration test program for the co-firing of Refuse Derived Fuel (RDF) and petroleum coke is planned. A demonstration of eastern coals may also be included in the test program in cooperation with EPRI, Consolidated Edison Company of New York (Con Ed) and the Empire State Electric Energy Research Corporation (ESEERCO). Tests conducted at NSP's French Island 15 MW AFBC retrofit unit and EPRI's 6' X 6' pilot plant AFBC facility, firing Sarpy Creek Coal and using Linwood limestone as the sorbent bed media, have provided a technical basis for the Black Dog design.

Demolition and refurbishment work on the existing Black Dog Unit began in September, 1984. Construction of the new AFBC boiler retrofit by Foster Wheeler Energy Corporation (FWEC) is scheduled to begin in March, 1985, with initial operation planned for the first quarter of 1986.

Important features of the project include:

- Largest AFBC boiler retrofit to date
- 40 MW capacity increase
- 25 year power plant life extension
- Low leakage regenerative air preheater design
- Electrostatic precipitator performance improvement
- Alternate fuels co-firing capability
- Reduced emissions on a per MW basis

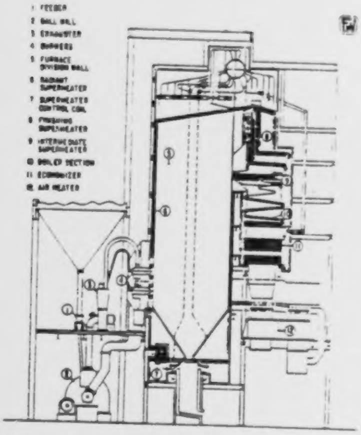
ORIGINAL STEAM GENERATOR DESCRIPTION

The original Black Dog Unit 2 boiler (Figure 7) was a FWEC non-reheat steam generator with a maximum working pressure of 1,770 psig, a maximum peak steaming rate of 860,000 lb/hr and a final steam temperature of 1,000°F (Figure 8).

The unit had a fixed external pressure casing with top supported pressure parts and was designed for pulverized coal, oil or natural gas firing in the front wall only.

A few pertinent characteristics of the unit as originally designed were as follows:

- The furnace front wall consisted of radiant superheater surface with steam flow both up and down the furnace wall.
- The unit had a full furnace division wall.



ORIGINAL PULVERIZED COAL FIRED BOILER
BLACK DOG UNIT 2
FIGURE 7

NOMENCLATURE	UNITS	MAXIMUM NORMAL LOAD*
DESIGN PRESSURE	PSIG	1,770
BOILER DRUM PRESSURE	PSIG	1,664
SUPERHEATER OUTLET PRESSURE	PSIG	1,575
SUPERHEATER OUTLET TEMPERATURE	°F	1,000
TURBINE THROTTLE STEAM FLOW	MB/HR	820
ECONOMIZER INLET TEMPERATURE	°F	445
REGENERATIVE A.P.H.		
• AIR INLET TEMPERATURE	°F	80
• FG OUTLET TEMPERATURE (WITH Lkg.)	°F	290
EXCESS AIR AT ECONOMIZER OUTLET	%	25
BOILER EFFICIENCY	%	86.75

*UNIT ALSO DESIGNED FOR FOUR HOUR PEAK LOAD

ORIGINAL FOSTER WHEELER
UNIT 2 PERFORMANCE SUMMARY
FULTON ILLINOIS COAL
FIGURE 8

- The unit had no furnace arch.
- The convection pass gas velocity at the top of the down pass was approximately 70 fps.
- The horizontal convection pass surface consisted largely of gilded ring-extended surface boiler and economizer surface.
- The two (2) regenerative type air preheaters were located directly below the economizer and were subject to plugging from broken refractory and sintered ash.
- When firing western coals, the unit load was curtailed to approximately 85 MW gross generation due to both pulverizer and fan capacity limitations and furnace slagging problems.

EXISTING EQUIPMENT TO BE USED

The basic philosophy of the project is to maximize the use of the existing Unit 2 power plant equipment while involving, to the maximum extent possible, existing plant personnel in the demolition, equipment refurbishment, repair and upgrade phases of the project to achieve the most cost-effective conversion to AFBC operation.

It is also the project philosophy to specify new equipment to current codes and standards while holding existing equipment to original codes and standards to the maximum extent practicable, safe or allowable.

PILOT PLANT TESTS

It is the intent of the project to utilize where practical all applicable information available from AFBC pilot plant, prototype or demonstration test programs either completed or currently under way.

DEMOLITION

Demolition work for the boiler retrofit commenced as of September 13, 1984, and is rather extensive as shown in Figure 10. Most of the original boiler casing will be removed and replaced with a stiffer design to increase the boiler's gas side design pressure rating. Removal of asbestos from the unit where exposed by demolition activities is a significantly time consuming and expensive procedure for the project. NSP is performing this function with Force Account personnel for monitoring, removal and disposition.

AFBC STEAM GENERATOR AND AUXILIARIES

Figure 11 shows the predicted performance for the AFBC retrofitted FWEC boiler while Figure 12 is a sectional side view of the unit as it will look when modifications are completed in 1986.

Due to certain design limits of the existing boiler and its related auxiliaries, and due to NSP's desire to increase the unit's rating from 100 MW to 125 MW gross generation, certain job specific design requirements were necessary to facilitate the Black Dog Unit 2 AFBC conversion in the available space. These requirements are as follows:

- Bed superficial velocity is specified at 10 fps maximum to minimize the carryover of unburned coal and unreacted limestone and thus reduce the recycle rate to levels approaching those used on stoker coal fired units.

  This requirement is necessary due to a design limitation on convection pass gas velocities of approximately 50 fps at the maximum continuous rating of the unit. The particulate loading to the existing particulate removal system must also be maintained at suitable levels through proper recycle system design so that the outlet loading from the unit can be controlled to NSPS levels without having to replace the precipitators. Some upgrading of the particulate removal equipment and controls is planned where necessary.

- The unit will be designed to burn Sarpy Creek Coal as well as other sub-bituminous coals and lignites with a maximum SO_2 removal requirement of 80 percent while using the available alkali in the coal ash to reduce limestone consumption.

  Alternate fuels such as RDF, petroleum coke and higher sulphur content eastern coals will also be test fired in the unit to determine their potential use.

- The unit will be designed with an overbed coal and limestone feed system which is the project's preference for large AFBC units. The unit will also be designed with overfire air ports located above the coal feeder inlets to the furnace to disburse the incoming coal fines from the feeder discharge area.

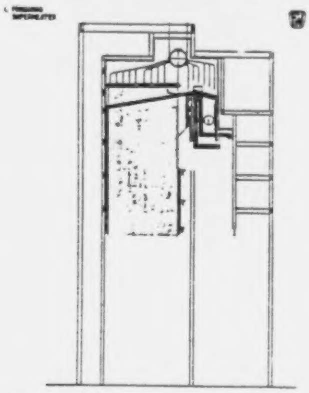
- The two existing air preheaters will be replaced with a single low leakage type regenerative air preheater furnished by CE Air Preheater Corporation to handle the higher pressure drops, flows and particulate loading requirements of the retrofit.

- A new multiclone dust collector unit will be added between the boiler outlet and the air preheater inlet to help compensate for the higher particulate loading from the boiler to the precipitator and to provide high carbon content fly ash material to the overbed recycle system when required.

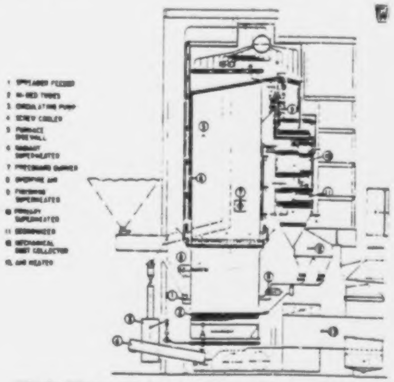
- New forced draft fans and modified induced draft fans will be installed to provide the higher static head and flow requirements of the AFBC system.

AFBC STEAM GENERATOR SYSTEM
HEAT AND MATERIAL BALANCE
FIGURE 11

NOMENCLATURE	UNITS	SARPY CREEK PERF COAL
TURBINE THROTTLE PRESSURE	PSIG	1,450
MAIN STEAM TEMPERATURE	°F	1,000
NET GENERATION	MW	115
GROSS GENERATION	MW	125
TURBINE THROTTLE STEAM FLOW	KB/HR	1,039
ECONOMIZER INLET TEMPERATURE	°F	469
NET PLANT HEAT RATE	BTU/KWH	10,930
EXCESS AIR AT ECONOMIZER OUTLET	%	18.5
AIR PREHEATER AIR TEMPERATURE ENTERING (FD FAN/AIR PREHEATER)	°F	80/110
AIR PREHEATER LEAKAGE	%	10
AIR PREHEATER FLUE GAS TEMPERATURE IN	°F	690
AIR PREHEATER FLUE GAS TEMPERATURE OUT	°F	350
BOILER EFFICIENCY	%	87
CARBON UTILIZATION	%	98
CO IN FLUE GAS	PPM	210
NOx IN FLUE GAS	PPM	243
SO_2 LIMIT (NSPS)	#/BTU x 10^6	0.6
SO_2 REMOVAL REQUIRED	%	72
Ca/S MOLE RATIO (LIMESTONE)	-	1.7
GROSS HEAT INPUT FROM FUEL	BTU/HR x 10^6	1,257
FLUE GAS WEIGHT AT AIR PREHEATER INLET	KB/HR	1,260
COMBUSTION AIR WEIGHT TO AFBC	KB/HR	1,129
FUEL BURNED	KB/HR	147.9
LIMESTONE REQUIRED	#/HR	7,375
TOTAL WASTE SOLIDS	#/HR	23,239
TOTAL SOLIDS TO BED DRAIN	#/HR	4,606
TOTAL SOLIDS ENTERING CYCLE	#/HR	18,783
FG WEIGHT TO ESP INCLUDING 10% AIR LEAKAGE	KB/HR	1,403
FLUE GAS (AT 800 FT.)	ACFM	442,913



DEMOLITION OF ORIGINAL BLACK DOG UNIT 2 BOILER
FIGURE 10



COMPLETION OF BLACK DOG UNIT 2 RETROFIT
FIGURE 12

The expansion of the lower furnace plan area required to accommodate the specified 10 fps fluid bed superficial velocity is to the north and south sides of the existing furnace. This approach requires minimum modifications to the existing boiler support steel and reduces the complexity and cost for the coal and limestone feed systems. The new AFBC furnace system will be bottom supported. No new piling or substructures are required for the retrofit.

This AFBC retrofit approach, however, does require a circumferential seal around the furnace to accommodate the differential expansion where the existing furnace and the new AFBC system are joined. This circumferential seal is a combination water/mechanical and slipjoint seal with the furnace-gas-side pressure balanced at atmospheric pressure at the seal elevation to minimize the potential leakage rate.

The new AFBC system as well as all of the remaining water cooled convection pass and furnace enclosure pressure parts will be designed for forced circulation.

The AFBC conversion approach at Black Dog will provide for significant combustion residence time in the furnace and should result in a relatively low recycle rate requirement for achieving the guaranteed unit limestone utilization rate and coal combustion efficiency. This conversion approach also results in the limestone and coal feeders and the overfire air and ash reinjection ports arranged in a manner similar to that used on a conventional stoker coal-fired unit.

The project anticipates that these special design considerations will all result in the reliabile and economical operation of the unit.

Input from three demonstration prototype and pilot programs has already been incorporated into the design for the Black Dog unit wherever possible. Subsequent information, as it becomes available and as appropriate, will be incorporated into the unit design through design flexibility and contingency planning considerations provided in the basic design of the AFBC and related systems for the retrofit.

COAL AND SORBENT HANDLING AND STORAGE FACILITIES

The existing coal handling and storage facilities are concentrated to the east of the powerhouse. There are presently four storage areas for coal. Two areas contain approximately 250,000 tons each of Illinois coal while the other two areas contain approximately 250,000 tons each of western coals. The size of the coal storage areas are based on maintaining a four-month supply of coal to operate the plant during the winter months when delivery by barge is not possible.

Coal for the AFBC retrofit unit will utilize the existing unloading, yard storage, crushing and handling facilities. Space provisions have been identified by the project in case additional in-plant coal preparation for the AFBC retrofit boiler should prove necessary in the future.

The existing coal storage within the plant for Unit 2 consists of two 700 ton coal silos. The bottom of the existing coal silos will be modified as necessary to connect the silo outlets to the four new coal scales which will deliver the coal to the four non-segregation type coal chutes and twelve spreader feeders located at the front of the boiler. The new limestone receiving, handling and storage systems for Unit 2 will consist of two new 10 ton limestone storage silos located outboard of the existing coal silos and fed pneumatically from a live storage silo located inside the old Unit 2 chimney. The limestone will be fed to the top of the fluid bed through four gravity chutes by means of four rotary feeders located immediately below the limestone storage silo outlets.

The project has decided to proceed at this time on the basis of receiving precrushed limestone delivered by truck to the plant until more is known concerning actual limestone requirements and alternate sources of supply. Space provisions have been identified for the installation of any necessary limestone preparation equipment at the plant in case this should prove to be cost effective at some future date.

WASTE HANDLING AND DISPOSAL FACILITIES

The fly ash and AFBC waste handling systems will receive pre-cooled AFBC spent bed waste and uncooled fly ash which will be pneumatically conveyed to a new ash collection silo.

The new fly ash and waste disposal systems will also receive, upon demand, fly ash recycle "blowdown" from the new multiclone flyash collection system. This system will provide control of the fly ash recycle rate back to the furnace of the AFBC unit. The combined fly ash and waste disposal systems for the new multiclone and AFBC systems will be a combination vacuum/positive pressure system. The existing fly ash disposal system for the Research Cottrell (RC) and Belco Precipitators is a vacuum system and will not be changed.

FLUE GAS HANDLING AND PARTICULATE CONTROL SYSTEMS

The flue gas handling and particulate emissions control systems consist of the upgraded primary and secondary precipitators and future provisions for a flue gas conditioning system. The flue gas is discharged from the Unit 2 particulate removal system through a common stack for the power plant. This new, taller stack was installed in the mid 1970's when the second stage precipitators were added as part of NSP's plans to comply with more stringent stack gas emissions regulations.

The combined capacity of the precipitators based on the Sarpy Creek performance coal is approximately 450,000 ACFM with a precipitator efficiency of 99.8 percent.

The provisions for injecting the flue gas conditioner into the flue gas stream will be located at points before each of the primary and secondary precipitators.

The flue gas conditioning system, if required at a later date, will be used to control the electrical resistivity of the fly ash to levels that will tend to improve the collection efficiency of the existing precipitators. By providing a contingent plan to enhance the fly ash collection characteristics in this manner, a considerable cost savings is realized in minimizing initial precipitator rework requirements.

The two 50 percent capacity induced draft fans when modified will be rated at 270,000 ACFM each at 28 in.WG net conditions; will be driven by variable speed, 2500 hp motors and will remain where presently located between the primary and secondary precipitators.

INSTRUMENTATION AND CONTROLS

The existing Units 1 and 2 control systems and control room will be replaced with new Data Acquisition and microprocessor-based Distributed Control Systems (DAS/DCS) operated from a new common control room for all four of the Black Dog units. The existing Units 1 and 2 control room will then be modified and made available for the Unit 2 AFBC test program. This arrangement will help isolate the special test equipment and activities from the normal operations of the plant.

The data acquisition and automatic control systems will be directly comparable in technological development, reliability and performance with those provided on a new conventional pulverized coal-fired plant.

The controls for the existing balance of plant equipment which are now operated from the existing control room will be upgraded as part of the planned rework of the unit and integrated into the DCS. In addition, the DCS will provide coordinated boiler and turbine control capability from startup to full load operation. This will provide a unified operator control philosophy for all major plant controls as well as shared training, maintenance, spare parts, and operator interface stations.

Redundant CRT-based control consoles will provide a variety of interactive color graphics, preformatted displays, trend displays, alarms and equipment status messages for the control and data acquisition systems. Specified critical control loops will be backed up with console mounted, hard wired, manual-automatic selector stations.

Auxiliary systems that support plant operations and operate on an intermittent basis will be controlled by programmable controllers and/or local control stations unless system complexity or operator convenience dictates operation from the main control room. The programmable controllers will be linked to the DAS to transmit common alarm signals and equipment status messages. Communication with the DCS will be via a redundant co-axial cable data highway.

The DAS will consist of a digital computer system which is linked to the DCS data highway. The computer will also perform such tasks as process modeling and optimization and will support management information systems functions.

Miscellaneous Modifications

The flue gas and air ducts will be reinforced as necessary to withstand the new forced and induced draft fan pressure requirements. The existing boiler and primary precipitator gas side pressure casings will be reinforced as required for the new boiler operating conditions.

Critical plant services piping in the way of the Unit 2 retrofit effort will be relocated as necessary.

Some cable tray and conduit will be disturbed by the demolition and retrofit work involved and will have to be replaced and/or relocated. A concerted effort will be made to preserve as much of the cable as possible in the existing raceways for reuse.

All 2300 volt and 480 volt switchgear presently used for the pulverized coal systems will be utilized for new AFBC loads wherever feasible.

To minimize cost and conserve space, previously abandoned chimneys from Units 1, 2, and 3 will be utilized for limestone and waste storage.

TEST PROGRAM DATA ACQUISITION

A complete DAS, separate from the Unit 2 DAS/DCS, will be provided for the Phase IV test program. Equipment procurement and installation requirements will be determined during Phases I, II and III.

The Unit 2 DAS/DCS uses a data highway concept which will permit communication with the test program DAS, if required, to verify data.

OPERATING PLANS

Phases I and II

Following the completion of the Phase I work, and as an end result of the Phase II effort, the unit will be started up, placed into automatic operation and released to NSP operations.

Phase III

For the next six months, the unit will be operated to meet both system demand and determine the maximum operational capability of the unit. The objective of this phase is to verify the increased design capability of the boiler at 1,039,000 lb/hr steam flow and the turbine generator at 125 MW.

Phase IV AFBC Test Program

Once the maximum capability and performance of the plant has been confirmed to be as guaranteed, the unit will be operated commercially in a combination cycling/peaking mode for the next three years while the AFBC test program is being conducted.

This should result in ample time for testing in various and desired operating modes and for any required outages of the unit for inspection prior to and immediately following a test.

The complete test program, yet to be developed, will coordinate maximum and minimum unit load tests with NSP's system load requirements on a seasonal and daily basis.

NSP's expectations for Unit 2 electrical production during the three year test program is anticipated to result in a unit capacity factor of from 20 to 40 percent, depending on NSP's system load demand and the requirements of the test program.

COMMERCIAL OPERATION

During and subsequent to Phases III and IV portions of the Black Dog Unit 2 retrofit program, commercial operation of the unit is anticipated as follows:

- The plant will be converted with the anticipation of a 25-year operating life and a 20-year pay back.

- The unit will be operated on automatic dispatch in a combination of cycling and peaking operation depending on both system load demand and economic load dispatching.
- The units capacity factor is projected to range anywhere from 15 to 65 percent over its entire 25-year extended life depending on system demand.

The unit will be designed to provide a turndown capability of approximately 5:1 with a superheater temperature control range of from 50 to 100 percent of the 125 MW unit rating.

ENVIRONMENTAL EFFECTS

NSP has leased to the U.S. Fish and Wildlife Agency the existing Black Dog Lake and surrounding portions of the Black Dog plant property not used for plant operations. The project will utilize the existing property still available to it for limestone as well as coal storage with no adverse impact on the environment. Almost all of the new construction for the Unit 2 AFBC retrofit will be contained within the plant and will, as a result, minimize the environmental impact on the surrounding areas.

The increased generating capacity derived from the retrofit will also have minimum impact on the environment as the unit will be designed to meet or exceed most of the objectives of NSPS. The heat rejection from the unit will increase slightly. The circulating water system presently discharges to the Black Dog Lake. Further studies will be required during the detail engineering stage, but it is anticipated that this impact on the environment will also be minimal.

Terrestrial and aquatic ecology, solid waste disposal, ground and surface water quality and existing noise levels are not expected to be adversely impacted.

Relevant socioeconomic and environmental issues have been addressed by the licensing and permitting process.

LICENSING AND PERMITTING REQUIREMENTS

The permitting and regulatory process for the Black Dog AFBC retrofit project was less rigorous than that required for a new unit. The major permit requirement was from the Air Quality Control Division of the Minnesota Pollution Control Agency (MPCA). Filing activities for permits and licenses began on July 1, 1983.

Discussions with the MPCA concerning acid rain and NSP's project design objectives proved favorable. The MPCA views this project to be consistent with an agreement NSP executed with other parties involved in the Sherburne County Unit 3 Certificate of Need hearing and thus granted NSP a Construction and Operating permit to implement the AFBC retrofit project effective as of June, 1984.

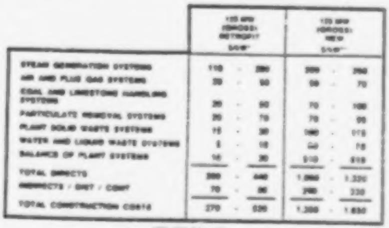
ESTIMATED CAPITAL COSTS

The combined estimate summary for the project when completed and ready for operation and testing is as follows:

	(X $1,000)
Total Direct Costs:	$33,600
Distributable & Indirect:	$ 6,500
Subtotal	$40,100
Demolition	$ 1,400
Escalation	$ 3,000
Allowance for Funds Used During Construction(AFUDC)	$ 4,100
Budget Contingency	$ 1,400
TOTAL	$50,000

The mid 1984 costs have been escalated according to the project schedule.

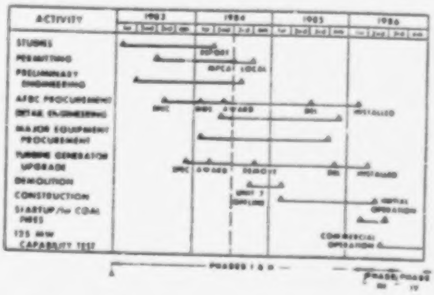
Figure 16 depicts the project's estimate of a typical project cost utilizing AFBC technology in either a new grass roots or retrofit unit design.



	[illegible] RETROFIT	[illegible] NEW
STEAM GENERATION SYSTEMS	110 - 200	200 - 250
AIR AND FLUE GAS SYSTEMS	30 - 50	50 - 70
COAL AND LIMESTONE HANDLING SYSTEMS	20 - 50	70 - 100
PARTICULATE REMOVAL SYSTEMS	20 - 70	70 - 90
PLANT SOLID WASTE SYSTEMS	15 - 30	100 - [illegible]
WATER AND LIQUID WASTE SYSTEMS	5 - 10	40 - [illegible]
BALANCE OF PLANT SYSTEMS	10 - 30	[illegible] - [illegible]
TOTAL DIRECTS	200 - 440	1,060 - 1,320
INDIRECTS / OWN'T / CONT	70 - 90	240 - 330
TOTAL CONSTRUCTION COSTS	270 - 530	1,300 - 1,650

[illegible]

PREDICTED PROJECT COST FOR COAL FIRED FLUIDIZED BED BOILER POWER PLANT
FIGURE 16



MILESTONE SCHEDULE
BLACK DOG UNIT 2 AFBC RETROFIT PROJECT
FIGURE 17

The following project milestones have been established for the retrofit effort (Figure 17).

Project Authorization	1/02/84
Award AFBC System Contract	5/18/84
Start Detailed Engineering 125 MW Plant	5/18/84
Start Demolition	9/12/84
Start Boiler Erection	2/15/85
Commercial Operation 125 MW Plant	4/01/86

ECONOMIC ANALYSIS

NSP's Power Supply Planning Department performed a comparative economic evaluation of the Black Dog fluidized bed retrofit project to add 40 MW to the NSP generation system as opposed to the installation of new fossil fuel fired generating capacity. The criteria included production cost savings and fixed costs consisting of capital, fuel inventory, fixed operation and maintenance (O&M) and outage costs. The criteria for economic evaluation of the Black Dog fluid bed demonstration project was identical to that criteria used for new generation facilities going into service at the same time or for continued operation of Black Dog Unit 2 without the retrofit. A signficant difference in NSP's economic evaluation of the demonstration unit is related to risk or uncertainties in calculating benefits for extending the normal life of the unit.

The economics of the retrofit project was based on an annual average capacity factor of from 20 to 40 percent operating in a cycling mode.

The economic studies used the same forced outage rates for the AFBC as for existing NSP pulverized coal fired units.

DESCRIPTION OF TEST PROGRAM

OBJECTIVE

The objective of the test program phase of this project is to demonstrate to potential industrial and utility users of coal-fired steam generating equipment that the fluidized bed combustor is an economically feasible method of burning coal in an environmentally acceptable manner. To accomplish this objective, environmental control and thermal performance of the unit will be measured and reported at several operating conditions. The startup and load following ability and the ability to operate for extended periods will also be evaluated and reported.

Following the startup period, NSP will provide FWEC with access to the unit to allow for performance testing of the unit. Such testing will include the gathering, evaluation and reporting of operating, environmental emissions and economic data. The boiler and associated systems will be operated during this period with primary emphasis on data gathering and testing by the contractor and the project.

For an additional three-year period, access to the unit will be permitted to the AFBC test program participants to gather additional performance data, conduct specific tests and obtain operating data from operating logs and records. The unit will also be made available for site visits by potential users of AFBC technology and other interested parties during this three-year period while the boiler and auxiliary systems will be operated by NSP in response to system load demand and the agreed to requirements of the AFBC test program.

BOILER THERMAL PERFORMANCE

The efficiency of the boiler will be determined in accordance with the guidelines of the ASME Power Test Code 4.1 and 4.3 for Steam Generating Equipment. The boiler efficiency will be determined using the heat loss method such that all unaccounted for losses do not exceed one percent. A heat and material balance will be prepared for each test.

STACK EMISSIONS

Emissions from the stack will be sampled for SO_2, NOx, CO and particulate matter and quantified for compliance with applicable EPA emission standards and the Unit 2 MPCA permit using EPA approved test methods. Continuous stack gas monitors provided by the project will be calibrated against the results of the compliance tests and will subsequently be used to determine Unit 2 stack emissions during boiler performance testing. The in-duct monitors will continuously measure opacity, SO_2, NOx, CO and O_2 as required for efficient and proper operation of the unit.

COMPONENT PERFORMANCE

Tests will typically be conducted during the three year test program to evaluate the performance of individual components of the system of specific interest at selected operating conditions.

AFBC unit components and systems currently identified for testing are as follows:

- Cyclone dust collector efficiency, size distribution and fly ash chemical composition.
- Precipitator efficiency and outlet grain loading.
- Spent bed material handling system capability and reliability.
- Coal and limestone feed system flow rate, size distribution and moisture content.
- Fly ash reinjection system performance and reliability.
- Air Heater efficiency and air leakage rates

EVALUATION OF ALTERNATE FUELS AND SORBENTS

A full load performance test and emission test will be run to evaluate unit performance on each alternate fuel and sorbent tested. The evaluation will include an appropriate period for balancing of the bed with the specific fuel and/or limestone being tested before the actual data collection period begins.

ENGINEERING DESIGN DATA

A series of tests will be run to collect engineering data which will advance the overall "state-of-the-art" development of fluidized bed combustion technology. These tests will include, as a minimum, the following:

- Effects of cyclone dust reinjection rate
- Transient-rate of bed cooldown tests
- Furnace in-bed and convection pass heat transfer rates and surface performance

Statement
of
The Southern California Edison Company

by

Dr. Lawrence T. Papay
Senior Vice President

CONCERNING THE ACTIVITIES AND EXPERIENCES OF THE SOUTHERN CALIFORNIA EDISON COMPANY IN THE AREA OF AVAILABLE AND EMERGING TECHNOLOGIES FOR THE CONTROL OF ACID RAIN PRECURSORS

Before the
Subcommittee on Environmental Protection
of the
Committee on Environmental and Public Works
of the
United States Senate

March 4, 1987

Room 406, Dirksen Senate Office Building

Coal is by far the United States' largest indigenous fossil fuel resource. Several hundred year's supply at current consumption rates are known to be economically recoverable with today's technology. These "proven reserves" are so great that the coal industry has little economic incentive to conduct further exploration, even though it is suspected that they may have only scratched the surface.

Coal is presently utilized to power 57% of this country's electrical generation. The continuing use of and increased demand for this fuel are in conflict with stringent air pollution and solid waste control regulations. The Cool Water partners, however, are convinced that the technologies being proven at their demonstration facility provide the answer to this dilemma.

The Cool Water Coal Gasification plant, is half way through its five-year commercial demonstration (6/84-6/89) program and has proven that integrated gasification combined-cycle (IGCC) technology can reliably produce electrical power while limiting emissions of SO_2, NO_x and particulates to a rate as low or lower than one-tenth of the federal new source performance standards for coal-fired plants. The solid effluent streams at Cool Water include a slag that has been declared non-hardardous (which Cool Water plans to market as road-bed aggregate, concrete foundation mix, or similar applications) and a 99.5% pure elemental sulfur which has been sold since initial operation. Process water requirements are 40% less than those of a conventional coal-fired utility plants equipped with flue-gas desulfurization units for stack gas scrubbing (Reference 1).

The IGCC technology employed at Cool Water has now been demonstrated to convert coal to electricity in an environmentally superior fashion (Reference 2).

Despite its success, additional testing should be performed to further improve system flexibility, reliability and efficiency. This effort would provide the necessary assurances to operate commercial gasification facilities on a wide range of coal resources with varying quality parameters.

I. INTRODUCTION

When the oil embargo hit the United States (as well as other nations) in 1973, the importance of developing alternative methods of power generation was dramatically brought home. Skyrocketing prices and diminishing supplies of natural gas and oil made it clear that alternative fuel sources/technologies needed to be explored. In 1973 the Southern California Edison Company (Edison) used oil and gas to generate 58% of its electricity, and burned 63 million equivalent barrels of fuel oil and gas, which equates to about 16 million tons of coal (Reference 3).

In 1977 Edison and Texaco Inc., began preliminary discussions about the possibility of utilizing integrated gasification combined-cycle technology for the commerical production of electricity. This is one of many alternative technologies that Edison has evaluated and is utilizing to reduce its dependence on foreign fuel sources as well as for other goals.

The Cool Water Coal Gasification program was formally initiated in July, 1979, upon execution of the original Texaco/Edison agreement which has since been amended to provide for contributions of capital and expertise by other participants. (See Table 1 and Figure 1 for capital funding and Participant's program functions, respectively). The Electric Power Research Institute (EPRI), Bechtel Power Corporation (Bechtel) and General Electric (GE) joined the program in 1980. The Japan Cool Water Program Partnership (JCWP) joined in 1982 (JCWP is a consortium of interested Japanese industrial organizations led by Tokyo Electric Power Company, the world's largest private utility). Two non-equity contributors, the Empire State Electric Energy Research Corporation (ESEERCO) and Sohio Alternate Energy Development Company also joined the program at a lower level of funding to obtain access to particular information from the program. All capital costs were thus funded by private industry.

Detailed engineering for the plant began in February, 1980. Bechtel began construction in December, 1981, immediately after the initial project funding was secured. Construction of the plant was completed ahead of schedule and under budget on April 30, 1984. The original concept of a $300 million plant was pared to a $294 million dollar capital budget. Final capital cost of the plant was $263 million.

The plant, located adjacent to Edison's existing Cool Water Generating Station in the Mojave Desert approximately mid-way between Los Angeles and Las Vegas, began commerical production on June 24, 1984. The location gives the program an excellent opportunity to prove an environmentally superior process for utilizing coal in a state with stringent environmental regulations. It is believed that if one can obtain the necessary permits to construct and operate a coal-based facility in Southern California, one should be able to do so most anywhere.

The Program began a five-year demonstration phase on behalf of its joint owners in June, 1984. The objectives of the demonstration are:

- -demonstration of acceptable system and equipment performance at a commercial scale.
- -confirmation of system compliance with environmental criteria.
- -verification of controllability of the integrated plant under all operating conditions.
- -assessment of equipment and system reliability.
- -preparation of operating, maintenance, safety and training procedures which could be applied to future plants.
- -development of a complete economic and technical data base.
- -demonstration of feedstock flexibility.

Operating successes in the nearly three years of production to date have placed the Program well underway in the accomplishment of these objectives. The Program is convinced that it now has a shelf-available technology that is environmentaly superior. The remainder of the Program's life will be utilized in endeavors to further improve the technologies and to test other coal feedstocks.

III. PROCESS DESCRIPTION

The plant utilizes an entrained, oxygen-blown Texaco gasifier to convert 1,000 tons of coal per day to a medium-btu synthesis gas. After particulate and sulfur removal, the gas is combusted in a gas turbine to produce electricity. In addition, steam is produced by recovering heat from the hot product gas in syngas coolers and from gas turbine exhaust gas in the heat recovery steam generator (HRSG). Steam from both sources is combined and superheated in the HRSG and then utilized in a steam turbine for production of additional electricity. A simplified block flow diagram of the CWCGP process is shown in figure 2.

The Program Coal is a specified Utah coal with approximately 0.4 weight percent sulfur. The program has also tested two high sulfur eastern United States coals. Illinois #6 coal, containing 3.1 weight percent sulfur, and Pittsburgh #8 coal, containing 2.9 weight percent sulfur, were sucessfully run in early 1986. Up to six other coals may be tested during the remaining portion of the five-year demonstration period.

Coal is received at the plant in 84 car unit-trains, bottom dumped in a specially designed enclosure which contains coal dust collection and suppression equipment and conveyed to two coal storage silos with 6,000 tons capacity each. From the storage silos, the coal is conveyed to the grinding section. The grinding trains produce a nominal 60% coal/40% water slurry, which is transfered to run tanks containing agitators to keeps solids suspended. The slurry is then pumped to the gasifier.

At the gasifier, which is a refractory-lined vessel mounted at the top of a radiant syngas cooler, the coal-water slurry is combined with 1,000 tons per day of oxygen supplied from an adjacent air-separation plant. The slurry and oxygen are mixed in a specially designed burner, partial oxidation reactions take place at 600 psig and 2,000°F-plus temperatures to produce a medium btu syngas consisting mainly of CO, H_2, CO_2 ,and steam (clean syngas composition is shown in Table 2). Most of the sulfur is converted to H_2S, with a smaller amount of Carbonyl Sulfide (COS) formed. The hot syngas and slag from the gasifier reactor discharge into the radiant cooler below, which generates 1,600 psig saturated steam. The slag drops into a water pool at the bottom of the radiant cooler and is removed through a lockhopper system. The syngas proceeds into a convection cooler where additional 1,600 psig saturated steam is generated.

From the convection cooler, the gas enters a carbon scrubber, where essentially all the fine particulates are removed and recycled. After further cooling, the syngas proceeds to the Selexol unit, which removes 97% of the sulfur. The clean, dry syngas (at approximately 280 btu/scf) from the Selexol unit is then contacted with water in a saturator prior to firing in the gas turbine. The water provides moisture addition that is needed to control nitrogen oxide (NO_x) emissions from the gas turbine. Alternatively, NO_x emissions can be controlled equaly well by the direct injection of steam at the combustion turbine.

The major components of the power plant are a gas turbine with electric generator (65 MW gross), a heat recovery steam generator (HRSG), and a steam turbine with electric generator (55 MW gross). The waste heat exhaust from the gas turbine is used in the HRSG to produce additional saturated steam. This steam (25%) combined with the steam from the syngas coolers (75%) is superheated in the HRSG and used to drive the 55-MW steam turbine generator. The design net electrical generation is 111 MW at 13.8 KV before deducting the power requirments for the air separation plant. Provisions have also been included to pipe the clean syngas to an existing oil- and gas-fired boiler (65 MW gross) of an adjacent conventional plant owned by Edison, in order to demonstrate the suitability of the medium btu syngas as a replacement fuel for conventional boilers.

IV. OPERATING EXPERIENCE

Cool Water operating experience to date has exceeded expectations and continues to improve.

The gasifier was first fired on May 7, 1984. Plant commissioning was completed only 47 days later and the program entered commercial production to begin the five-year demonstration period on June 24, 1984. The table below summarizes the plant commissioning accomplishments versus objective dates:

	OBJECTIVE DATE	ACHIEVED
• first btu	6/01/84	5/07/84
• initial electrical production from syngas	6/25/84	5/20/84

The table below summarizes production to date:

	6/84 through 2/87
GASIFIER OPERATION (hrs.)	14,254
COAL GASIFIED (tons dry)	575,071
GROSS ELECTRICAL PRODUCTION (kwh)	1,383,363,000
ON-STREAM FACTOR (%)	60.6
CAPACITY FACTOR (%)	50.3

Production factors include numerous testing periods when plant output was intentionally reduced to determine low-flow efficiencies, dynamic response, etc. They also include down times, some of which were extended for inspection to obtain data needed to evaluate the effect of the various coal feedstocks burned to date.

The plant achieved an average capacity factor of 70% from May 1986 through November 1986. The capacity factor is the power produced as a percent of design. This is an outstanding statistic considering the fact that the plant is a single train design. In September, 1985 the plant had its best production month to date with a capacity factor of 80%. Production goals continue to increase (even though scheduled demonstrative testing has significant adverse impact on full design production) and the Program will aggressively pursue them.

The primary cause of shutdowns has been equipment failures. Only 16% of the shutdowns have been process related and the majority of those were caused by plugging in coal slurry lines and fly ash slurry lines. The vast majority of the shutdowns occurred in the early days of operation.

The plant has had three scheduled outages for inspections and repairs. Major improvements were also made during these outages. Piping layout changes have significantly reduced plugging problems in the gasification plant. Minor process modifications made during outages have provided large operating benefits and have significantly improved plant capacity factors.

During the high sulfur coal tests, high corrosion rates were evident in certain sections of the syngas coolers. These rates presented no significant surprise in that the coolers were designed for the lower sulfur

Program coal. Several coupons and alternate metallurgy tubes were originally placed throughout the coolers and corrosion data, or lack of corrosion data, from these metallurgies gave excellent actual operations data for use in design of future plants for use of high sulfur coals.

The maintenance experience history for each piece of important equipment is being cataloged. After several thousand hours of operations, an outstanding data base is being established that will allow excellent equipment and material specifications for future plants using processes and equipment demonstrated at Cool Water.

Figure 3 shows the plant's operating statistics from initial startup through 1986. The trend is excellent and the only "dips" occur during planned shutdowns, for example, when the plant was shut down for final quench unit (back-up to the main gasifier) tie-ins or during testing periods. The operations team of process and utility people have worked superbly together.

V. PERFORMANCE

Gasifier performance has been better than originally expected at commercial scale. Actual performance on the three coals tested to date are given on the following page:

Plant Performance/Designed Feedstocks
(at 1,000 tpd throughput)

	DESIGN	ACUTAL PERFORMANCE		
coal	Sufco	Sufco	Ill. #6	Pitts. #8
sulfur content (wt. %)	0.48	0.4	3.1	2.9
oxygen consumption (tons/day)	962	908	885	1004
gross power production (mw)	114	116	120	129
by-product sulfur produced (tons/day)	4.6	3.8	30.0	27.0
carbon conversion (%)	98.3	98.3	97.2	97.8
gasifier refractory life (yrs.)	1	4	2	2
overall heat rate (btu/kwh)	11,510	11,550	11,700	11,460

(Reference 1)

Burner developments have eliminated any scale-up concerns. Carbon conversions for the three coals have averaged approximately 98 weight percent. Single pass carbon conversions have been high enough that the slag screen classifier, intended to separate fine high carbon content slag for recycle to the gasifier, has not been utilized.

The high carbon conversions are also being attained at lower reaction temperatures than originally expected. The lower gasification temperatures have lowered oxygen costs and extended refractory life. Actual oxygen consumption has been 6% lower than the design value. Gasifier refractory life is presently estimated to be four-year actual versus a one-year design value on the program design coal.

Plant heat rates have also been in line with original projections. Overall plant heat rates have been approximately 11,500 btu/kwh. The program projects that the heat rate can be lowered to 10,900 btu/kwh with minor plant improvements.

The plant has completed partial load and dynamic load following tests. Partial load tests were conducted at 70% of the design plant throughput. Carbon conversions decreased slightly and heat rates increased approximately 16% at the partial load.

VI. EMISSIONS

Environmental performance at the plant has been outstanding. Sulfur removal and recovery technology have made IGCC an extremely clean process. Sulfur emissions are controlled by the use of a sulfur removal unit (modified Scot/Claus). Sulfur removal/recovery efficiencies in the order of 98% and 99+% respectively result in the reduction of sulfur dioxide emissions by over 97% (table 3). By comparison, these measured emission levels are in the range of only 10%-20% of those allowed by the U.S. EPA new source performance standards for fossil fuel fired steam generating plants (Reference 2).

Oxides of nitrogen (NO_x) are controlled by saturation of the fuel gas with water, or by steam injection, which inhibits their formation in the combustion process. Performance tests have demonstrated emission levels of NO_x are contolled at an average of about 10% of the allowable levels of the U.S. EPA new source performance standards.

Extensive testing has been performed at the plant in conformance with requirments to create a database for future replication of IGCC plants. Additional pollutants such as carbon monoxide, hydrocarbons and particulate matter are equally as well controlled by this technology.

There are numerous technologies that control the emission of NO_x and SO_2 but none of the commercially available systems can achieve the removal of both NO_x and SO_2 as effectively and economically as the IGCC technology. Almost three years of commercial scale demonstration have shown the capability of this technology. Numerous tests have been conducted at the site and test data have been made available to the United States Department of the Treasury (Office of Synthetic Fuels Projects). Routine stack test data confirming low emission rates for criteria and non-criteria pollutants are presented in annual, quarterly and phase reports.

Slag from the gasifier, which had previously been classified non-hazardous by FEDERAL standards, has now also been classified non-harzardous by the California Department of Health Services. The program is currently pursuing markets for its slag as either road sub-base, fillers or abrasive materials.

Based on current research evaluations conducted by Edison, we know of no other coal burning technology that can meet the emissions levels produced at cool water: emissions levels which approach and, in some cases, improve upon those attained by plants burning natural gas.

•

VII. ECONOMICS

Economic evaluations at Cool Water continue. The program is building an economic and technical data base founded upon thousands of hours of operation. This data is being used to confidently predict the cost of electricity from mature IGCC plants using the processes demonstrated at Cool Water.

Since most of the technologies are designed to remove one specific pollutant, cost comparisons have to be done based on total plant pollution abatement. Recent studies by EPRI indicate the capital investment required for a 500 MW IGCC plant is comparable to that for a direct coal-fired plant of the same size with flue gas cleanup and that phased construction of the IGCC plant could result in a cost approximately 20% less than the direct coal-fired unit. Phased construction of an IGCC plant would consist of initially installing a gas turbine to be fired with natural gas or oil while these fuels were available at a low cost. Heat recovery steam generators and a steam turbine would be added as load growth continues and then a gasifier plant would be added to convert the plant to IGCC operation.

Phased construction offers several advantages. Large capital outlays are stretched out by matching load growth requirements more evenly, significantly minimizing the "at-risk" capital due to the short construction time-frame for the modules. Phased construction also improves the potential to take advantage of non-utility ownership of the gasification plant.

EPRI studies further indicate that the operating costs of a mature IGCC plant would be 10% lower than a direct coal-fired plant using flue gas cleanup. Preliminary analysis by the program inidicate that production costs continue to decrease as the plant progresses on its learning curve. These operating cost declines combined with atypical expenses for a demonstration plant provide insight to determine projected commercial production costs. Atypical costs include special testing costs, extraordinary record keeping costs, high heat rate and high oxygen costs due to the short amortization period for the oxygen plant.

IX. FUTURE PROSPECTS

Edison has gained significant experience in the design, construction and operation of the cool water plant. The experience gained in operation of the plant the past three years makes us confident that IGCC technology is an attractive candidate for future power generation on the Edison system. However, to move this proven technology into the commercial utility marketplace given the complicated political, technical and financial impediments will be difficult.

Despite the many successes, of the Cool Water Coal Gasification Program, much more remains to be done. With the current depressed oil prices and future projection of energy prices, the enthusiasm and the urgency to pursue an aggressive development effort to commercialize this promising technology has waned.

The federal government's support for the synthetic fuels industry has all but vanished and, by and large, advanced clean coal technologies have been left to the private sector to develop, demonstrate and commercialize. Even with the private sector capital commitment of \$263 million, the cool water program couldn't have become a reality without the \$120 million price guarantee by the Synthetic Fuels Corporation (now administered by the United States Treasury Department). This illustrates the crucial importance of public-private partnership and cooperation in advanced technology development, particularly during the high-risk, capital-intensive demonstration and initial commercialization phase. It is only a matter of time before oil and gas prices will resume their upward spiral and the utility industry must not be lulled to an over dependence on these fuels. Since 1978, oil consumption by electric utilities has been cut by three-fourths. Oil accounted for approximately 4 percent of electricity generated in the U.S. last year. These are astonishing and commendable achievements by an industry not known for its agility.

The most cost-effective approach to fund demonstration projects is something along the line of the Cool Water Program where interested parties pooled their technical expertise, operational experience and financial resources together with a price guarantee (or capital cost share) from the government to make it happen (Reference 4).

Cool Water is the first commercial-scale demonstration of a coal gasification plant being integrated with a combined-cycle power plant to produce electricity. Edison is convinced that the knowledge already gained in this demonstration would allow commercially viable replication at larger scales.

In addition to commercial applications which utilize the gasification technology for new power generating facilities, the technology has other important potential applications concerning conventional power generation. First, the technology could be used to retrofit existing pulverized coal facilities with a gasification plant rather than adding scrubbers, baghouses and other flue gas cleanup equipment in order to meet environmental regulations. This ability could also be used in oil and gas fired plants should either of these fuels be curtailed or become prohibitively expensive. Any plant with its existing boiler (or combustion turbine) and steam cycle in good condition could be a candidate for a gasification retrofit. Burner modifications to the combuster are required but they do not represent a large cost item.

At Cool Water, tests were conducted with syngas in an existing gas fired boiler of approximately 65 mw capacity. The tests demonstrated that the unit could be operated throughout its entire range of syngas load without problems. The unit operated well within environmental limits (including less than 100 ppm NO_x) during its acceptance test run.

There has been significant utility industry interest in applications of the technology, and in how well the plant has performed (see Awards & Recognitions in the Appendices). However, the utility sector is conservative and, generally speaking, no utility wishes to build a "first-of-a-kind" commerical facility costing hundreds of millions or billions of dollars. This is particularly true given regulatory overview of construction costs and the potential for stockholder liability of perceived cost overuns.

Although originally conceived with somewhat different objectives in mind, it is clear that the Cool Water technology can play an important role in the control of emissions from the use of coal to produce electricity. The Cool Water partners are willing to work with interested parties to further demonstrate the use of this technology if any concerns exist on the part of others.

XI. CONCLUSION

Now that we are nearing three years of operation at Cool Water, the plant has proven that IGCC is an economically competitive and environmentally superior process for the conversion of inherently "dirty", but domestically plentiful, coal to a clean burning synthesis gas for the generation of electrical power.

The technologies are shelf-available and ready for utility sector deployment. Scale-up of the gasification train and development of controls for integration of the total IGCC plant went very smoothly without major design difficultly. Further improvements of the process, as planned at Cool Water, should principally consist of operational knowledge and minor modifications which could be easily and inexpensively implemented at future plants.

In summary, Edison is convinced that IGCC is a commercially viable technology exhibiting environmental superiority. A nation that is truly the "Saudi Arabia" of coal must encourage the use of this clean coal technology.

TABLE 1

PROGRAM CAPITAL FUNDING
(Millions of Dollars)

Participants	Committed Funds
SCE	25
Texaco	45
EPRI	69
Bechtel	30
GE	30
JCWP	30
Subtotal	229
Contributors	
ESEERCO	5
Sohio	5
Program Loan	24
TOTAL COMMITMENT	263

TABLE 2

CLEAN SYNGAS COMPOSITION

Component	Mol % (Dry Basis)
CO	42.5
H_2	38.2
CO_2	18.6
CH_4	0.3
Ar & N_2	0.4
H_2S & COS	50 PPM

TABLE 3

AIR POLLUTANT EMISSIONS BY FEEDSTOCK
(U.S. EPA NEW SOURCE PERFORMANCE STANDARDS FOR COAL-FIRED PLANTS VS. CWCG PLANT DATA ATTAINED TO-DATE)

POLLUTANT	U.S. EPA NSPS (COAL)	SUFCO	ILL. NO.6*	PITTS. NO.8*
NO_X	0.60 LB/10^6 BTU	0.059 LB/10^6 BTU	0.094 LB/10^5 BTU	0.09 LB/10^6 BTU
SO_2	90% Removal 1.2 LB/10^6 BTU	97% Removal 0.034 LB/10^6 BTU	97% Removal 0.068 LB/10^6 BTU	97% Removal 0.087 LB/10^6 BTU
PARTICULATES	0.030 LB/10^6 BTU	0.0013 LB/10^6 BTU	0.0085 LB/10^6 BTU	— **

*PRELIMINARY DATA
**DATA PENDING

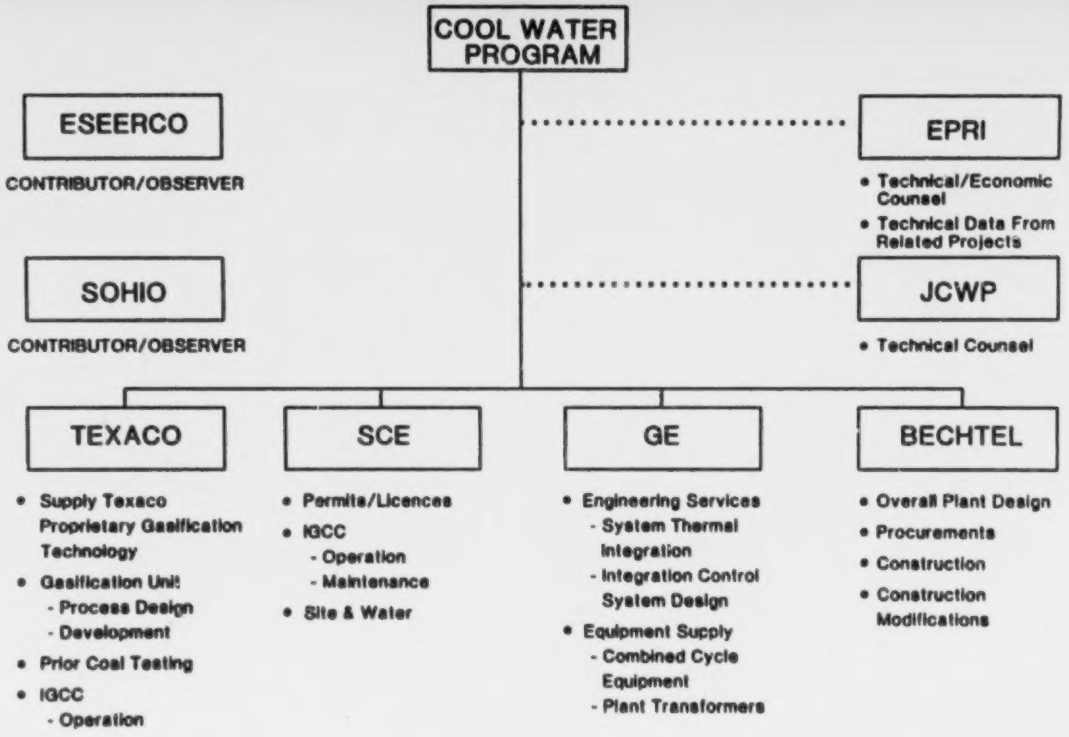

COOL WATER PROGRAM
ESEERCO
CONTRIBUTOR/OBSERVER
SOHIO
CONTRIBUTOR/OBSERVER
EPRI
• Technical/Economic Counsel
• Technical Data From Related Projects
JCWP
• Technical Counsel
TEXACO
• Supply Texaco Proprietary Gasification Technology
• Gasification Unit
- Process Design
- Development
• Prior Coal Testing
• IGCC
- Operation
SCE
• Permits/Licences
• IGCC
- Operation
- Maintenance
• Site & Water
GE
• Engineering Services
- System Thermal Integration
- Integration Control System Design
• Equipment Supply
- Combined Cycle Equipment
- Plant Transformers
BECHTEL
• Overall Plant Design
• Procurements
• Construction
• Construction Modifications

FIGURE 1

COOL WATER COAL GASIFICATION PROGRAM
BLOCK FLOW DIAGRAM

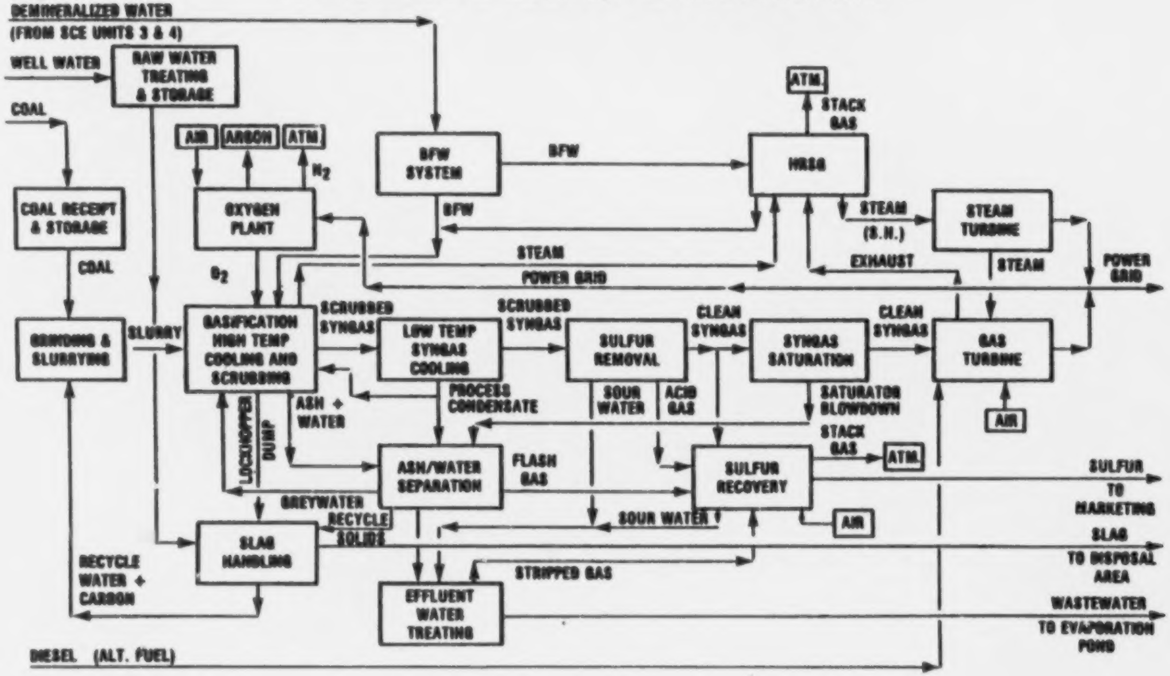

DEMINERALIZED WATER
(FROM SCE UNITS 3 & 4)
WELL WATER
RAW WATER TREATING & STORAGE
COAL
COAL RECEIPT & STORAGE
COAL
GRINDING & SLURRYING
SLURRY
AIR
ARGON
ATM.
N_2
OXYGEN PLANT
O_2
GASIFICATION HIGH TEMP COOLING AND SCRUBBING
LOCKHOPPER
DUMP
ASH + WATER
GREYWATER
RECYCLE SOLIDS
SLAG HANDLING
RECYCLE WATER + CARBON
DIESEL (ALT. FUEL)
BFW SYSTEM
BFW
BFW
STEAM
POWER GRID
SCRUBBED SYNGAS
LOW TEMP SYNGAS COOLING
PROCESS CONDENSATE
SCRUBBED SYNGAS
ASH/WATER SEPARATION
FLASH GAS
EFFLUENT WATER TREATING
STRIPPED GAS
SULFUR REMOVAL
SOUR WATER
ACID GAS
CLEAN SYNGAS
SULFUR RECOVERY
SOUR WATER
AIR
STACK GAS
ATM.
SYNGAS SATURATION
SATURATOR BLOWDOWN
CLEAN SYNGAS
HRSG
ATM.
STACK GAS
STEAM
(S.H.)
EXHAUST
STEAM TURBINE
STEAM
GAS TURBINE
AIR
POWER GRID
SULFUR
TO MARKETING
SLAG
TO DISPOSAL AREA
WASTEWATER
TO EVAPORATION POND

FIGURE 2

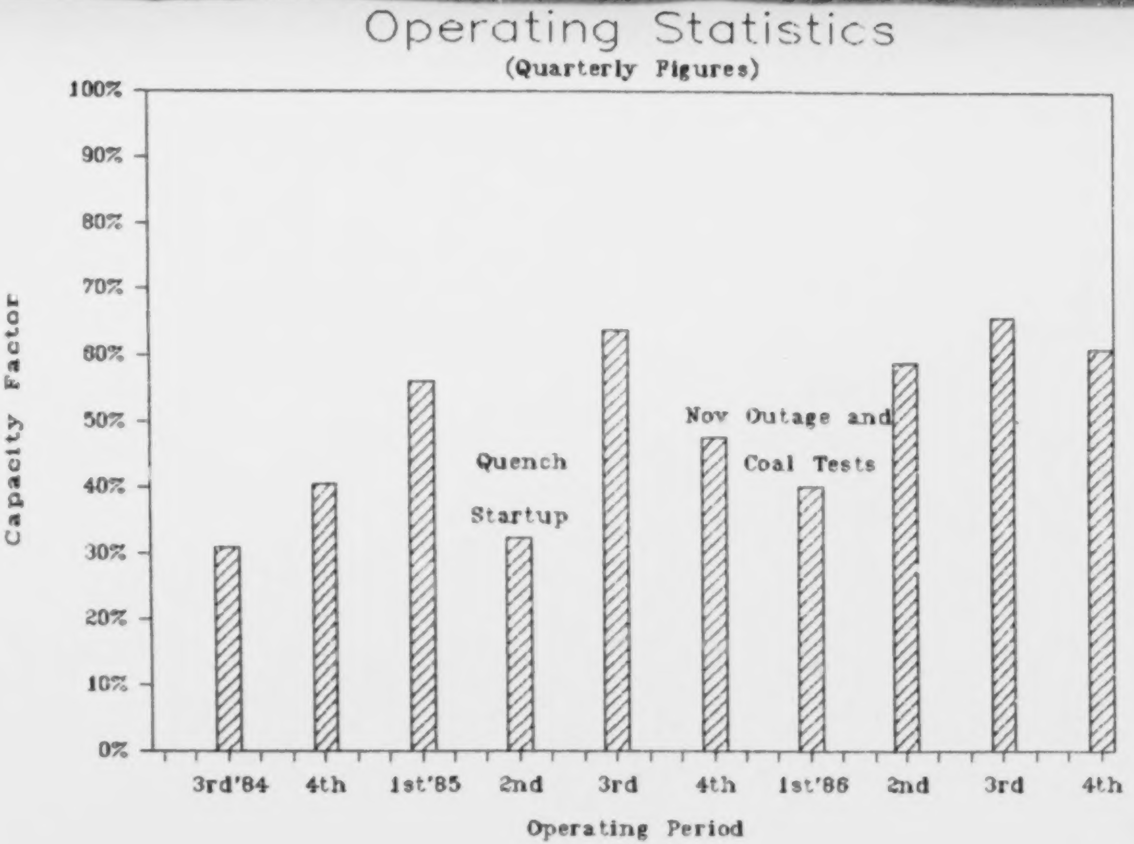

Operating Statistics
(Quarterly Figures)
Capacity Factor
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Quench
Startup
Nov Outage and
Coal Tests
3rd'84
4th
1st'85
2nd
3rd
4th
1st'86
2nd
3rd
4th
Operating Period

FIGURE 3

X. AWARDS & RECOGNITIONS

To date, the Cool Water plant participants have won several prestigious engineering awards. The Texaco coal gasification process received honorable' mention for the "1985 Kirkpatrick chemical engineering honor award" for its commercialization of the technology. Chemical Engineering magazine cited the use of coal gasification for electric power production as an example of diversity of the process.

The Institute for the Advancement of Engineering (IAE) called the Cool Water plant "possibly the world's cleanest coal-using plant". The IAE presented the plant with its "outstanding engineering achievement award" in 1986. Power Magazine awarded the plant its "1985 environmental protection award" which recognizes utility industry achievements in protecting the environment.

In 1984, the National Council on Synthetic Fuels Production awarded the First "Walter Flowers achievement award in sythetic fuels" to Texaco Inc. for development and commercialization of the Texaco coal gasification process. EPRI received the second Walter Flowers award, in 1986, for its contribution in synthetic fuels related to the Cool Water project.

In February 1987 Cool Water was named the recipient of the 1987 Energy Resources Technology Award by the American Society of Mechanical Engineers.

REFERENCES

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2. Ralph W. Grover, Preliminary Environmental Monitoring Results, paper presented at National AICHE meeting, Boston, Massachusetts, April 1986

3. Howard Allen, Fuel Choices For The Future: Cogeneration and New Alternatives, paper presented at National Coal Association Annual Convention, White Sulphur Springs, West Virginia, June, 1986

4. Robert Dietch, Utilities' Attitudes Toward Synthetic and Advanced Fossil Fuels Technologies, paper presented at Alternate Energy '86, Captiva Island, Florida, May, 1986

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SENIOR VICE PRESIDENT

TELEPHONE
818-302-1474

June 1, 1987

The Honorable George J. Mitchell
United States Senate
Committee on Environmental
  and Public Works
Washington, D.C., 20510-6175

Dear Senator Mitchell:

Pursuant to the request made in your May 8, 1987 letter, attached are responses to the questions from the Subcommittee on Environmental Protection.

Should you require additional information or have further questions, please contact me at the above address.

Very truly yours,

Enclosures

Q. Do you feel the federal government is sufficiently fostering research and development of acid rain control technologies?

-- Can the federal government do more to encourage such research and development?

-- What modifications would you recommend?

A great deal of the R&D effort sponsored by the federal government in the Clean Coal Program is directed toward developing new methods of generating electricity from coal which would be lower in SO_2 emissions then existing (unretrofitted with flue gas desulfurization (FGD) Systems) coal fired plants. After technology development, however, comes commercial demonstration. The government is only now showing adequate interest and support for commercial demonstration of new clean coal technologies. This is key to the future reduction of SO_2 and NO_x from fossil fueled boilers. Southern California Edison encourages increased government support of the DOE Clean Coal Demonstration Program.

The only process available for use in new plants which removes SO_2 and NO_x is coal gasification - integrated combined cycles developed by Texaco, Southern California Edison (and others) and now being operated at the 100 MW level at SCE's Cool Water Generating Station. Other technologies for the removal of NO_x from coal fired plants are still in the development stage.

There are many different FGD systems commercially available today which can remove 90-95% of the SO_2 emitted from conventional coal plants, even those using coal containing over 5% sulfur, with high reliability (some as high as 99%). These devices however, are costly and do not remove NO_x, also a precursor to formation of acid rain. The limestone injection process formerly pushed by EPA, known as LIMB, does not remove NO_x as advertised. Retrofitting existing coal fired boilers with such FGD technology will not be a cost effective solution for emission control.

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Q. Which technologies control NOx emissions most effectively?

-- Where are we in the development and use of these technologies?

-- How effective are these technologies in NOx removal?

This question is prefaced by a reference to ozone nonattainment in many cities across the country. Although nitrogen oxide emissions are a component of this problem, reactive organic emissions continue to be the major component to the problem in most metropolitan areas, including Los Angeles. In light of this, EPA continues to recommend ozone attainment strategies that focus on the reduction of reactive organic emissions rather than the reduction of nitrogen oxides. Premature reduction of NOx emissions could impede attainment of the ozone air quality standard. This point should not be lost in a debate to reduce NOx emissions for acid rain abatement.

Active research for the control of NOx emissions from stationary source emitters (boilers, furnaces) has been ongoing in the U.S. for the past 20 years. The development and availability of commercial systems, however, is limited due to market absence. The major driving force in creating this market, of course, is regulatory action, since the installation of NOx control technology does nothing to add to the financial bottom line of a company. As a result, active implementation of NOx technologies has occurred on a limited regional basis where regulatory activity has mandated its use.

The use of the word "effective" when describing a NOx removal technology must consider two important components - namely removal efficiency and cost - in order for the definition to be meaningful. Since a number of technologies exist for controlling or removing NOx, and since each technology has a different removal efficiency and associated costs, the most meaningful way to compare their "effectiveness" is in terms of dollars per ton of NOx removed.

Generally speaking, there are three approaches to reducing NOx emissions from stationary source emitters. One approach involves altering the combustion process with the use of low NOx burners, flue gas recirculation or firing with burners out of service. The second approach, which may or may not be considered a "subset of the first," is fuel switching. For example, the substitution of methanol for low sulfur oil or the use of a low nitrogen fuel for high nitrogen containing oil or coal are possible. The use of the developed (and patented by SCE) "Dual Fuel Combustion Technique" is included in this approach. The third approach involves post combustion removal and usually employs a gas phase chemical reaction such as Thermal De NOx, Selective Catalytic Reduction or the use of urea injection in the flue gas. It is our opinion, that for the most part, the most effective (as defined in the text) technologies from a previously uncontrolled source are those that alter the combustion process (low NOx burner, flue gas recirculation, etc). In terms of pure removal efficiency, without regard to cost, Selective Catalytic Reduction with ammonia is recognized as the best available control technology with an acknowledged removal efficiency of 80%.

In summary, much of the fundamental research concerning the formation, destruction, and removal of NOx from the combustion process in boilers has been performed. What remains to be done are full scale demonstrations of the emerging technologies, so that removal efficiencies and costs can be quantified. The ultimate tool to aid in the decision making process would be the development of a model to predict NOx based on the myriad of physical and chemical properties associated with the combustion of fuel and the employment of various technologies for NOx control.

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INDIRECT FIRED COMBINED CYCLE FOR UTILITY & INDUSTRIAL APPLICATIONS

by

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and

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INDIRECT FIRED COMBINED CYCLE FOR UTILITY & INDUSTRIAL APPLICATIONS

INTRODUCTION

Hague International (Hague), located in South Portland, Maine, has developed a multiple fuel, electric power generation gas turbine cycle intended for electric utility and industrial applications. This turbine cycle is expected to be competitive with other forms of power generation well into the next century. The key to the concept is a Hague ceramic heat exchanger developed specifically for gas turbines. This heat exchanger permits combustion of a wide variety of fuels outside the turbine. The energy from the combustion process is transferred through the heat exchanger to the gas turbine. The turbine working fluid is clean air. The turbine is referred to as an Externally Fired Gas Turbine (EFGT) and the combined cycle version is referred to as an Externally Fired Combined Cycle (EFCC) plant.

The principal advantages of this cycle are:

1) High efficiency in the conversion of fuel to electricity in small unit sizes.

2) Operates on a wide variety of ash bearing fuels with acceptable atmospheric emissions.

3) Consists of modular sub-assemblies which can be factory assembled for low first cost and short lead time from order to initial operation.

4) Adaptable to commercially available gas turbines and can accomodate improvements such as higher pressure ratios, higher firing temperatures and steam injection.

5) Optimizes the use of a bottoming cycle, such as a steam cycle, to improve overall thermal efficiency.

6) Suitable for progressive electric power generation to better parallel the load growth for electric utilities and thus reduce the financing costs.

7) Nitrogen and sulfur oxides emissions can be controlled by the use of sorbents in the combustion process and by conventional stack gas "clean-up" methods.

8) Can be used to upgrade obsolete steam plants increasing capaacity and providing heat rates that are comparable to large modern power plants.

The Hague International heat exchanger is marketed under the trade name of CerHx and is shown in Figure 1. The heat exchanger, combined with a suitable combustor, replaces the combustion systems within the conventional open cycle gas turbine. The heat exchanger accepts air at the turbine compressor discharge conditions, heats this compressed air to slightly higher temperatures than the required turbine inlet temperature, and, returns the air to the turbine section. The clean air delivered to the turbine replaces the products of combustion in the conventional open cycle thereby appreciably extending the service life of the turbine section. Only the static ceramic tubes in the heat exchanger are exposed to the high temperature corrosive effects of the impurities in the fuel.

Hague's CerHx, tubular heat exchanger has undergone a number of design refinements and tube material improvements over the last 8 years. During this period the heat exchanger has been operated in excess of one half a million hours under various high temperature environments in the aluminum and steel industries. It has also been tested on coal/oil mixture fuels at the Hague facilities in South Portland at inlet temperatures of up to 2800F.

During the last year Hague International, with the assistance of Stone & Webster Engineering Corporation (Stone & Webster), has focused its efforts on developing a demonstration project which would address electric utility interests in burning coal and industrial interests in burning other solid fuels. Hague and Stone & Webster currently have such projects under development. Work is also expected to be completed during 1987 on conceptual design packages for both 55 MW and 135 MW commercial utility designs of the EFCC cycle and industrial designs for 5 - 25 MW.

FUEL FLEXIBILITY

Changing economic environment, utility load growth patterns, and regulatory attitudes have led to a resurgence of utility and industrial interest in combined-cycle electric generating facilities. The desire for greater fuel flexibility has led to extensive research and development efforts. These efforts under the aegis of Federal Government agencies have been primarily directed to coal gasification and liquification. Gasification is considered a demonstrated technology, albeit widespread use has not been adopted for a variety of reasons principally economic in nature.

The EFCC/combined cycle version of the externally fired gas turbine offers a potential alternative to attain fuel flexibility and it does so by substituting a single heat exchanger for a very complex chemical process - i.e. the coal gassification process. This cycle combines the advantages of conventional combined cycles (high efficiency, modularity, short schedules, etc) with the ability to fire a wide range of ash-bearing fuels (coal, coal slurry, lignite, biomass, city refuse, etc.), a fuel flexibility that exceeds that available with the coal gassification process.

EFCC DESCRIPTION

The EFCC cycle is one of many variations of the Brayton cycle which have been proposed over the past few decades. A schematic of the EFCC cycle is shown in Figure 2. Atmospheric air enters the gas turbine compressor and is pressurized and delivered to a high temperature heat exchanger. Heat energy from the combustion process is absorbed by the working fluid (air) through the ceramic tubes, raising the air to turbine inlet temperatures (1750 to 2350F). The working fluid is expanded through the turbine, providing power to drive the compressor and generator. The turbine exhaust air is routed to the external combustor, providing low pressure high temperature combustion air to burn the ash-bearing fuel. The hot products of combustion from the combustor pass over the exterior surface of the heat exchanger tubes transferring energy through the tube walls to the high pressure working fluid within the tubes. The combustion flue gas from the ceramic heat exchanger passes through a heat recovery boiler to generate steam for process use, or, to produce additional electric power. The gasses then pass through conventional pollution control equipment and exit to atmosphere.

The high efficiency, and, simplicity of the EFCC cycle are its principal attributes. Moreover, commercially available gas turbines can be employed with relatively minor modifications to accommodate the heat exchanger in lieu of the the gas turbine combustion system (Figure 3). The combustion system required for the EFCC need not be more complex than that used for conventional steam generators employing "off-spec" fuels. Also, waterwall circuits can be used to prolong the life of the furnace/combustor walls.

The cycle can accommodate a wide variety of conventional fuel burners and burners that are currently under development. The advanced slagging combustor is an example of a developing technology that would be suitable for the EFCC cycle. Development of slagging combustors, could enhance the overall performance and economics of the EFCC cycle. Slagging combustor technology offers the ability to remove high percentages of sulfur and ash from the fuel in the form of molten slag, thus alleviating the ash burden on the heat exchanger and the duty of the gas cleanup equipment. The existing EFCC design utilizes dry FGD equipment and a baghouse for sulfur and particulate control. Successful demonstration of slagging combustors could significantly reduce the emissions control equipment performance requirements and overall construction costs.

The EFCC cycle is well suited to the use of steam bottoming cycles to generate additional electric power from the energy in the exhaust gas flow. The cycle permits the optimization of the gas temperature entering the bottoming portion of the cycle without the need for supplementary firing. One combustion system is all that is needed. EFCC combined cycles would yield generating efficiencies comparable to those of large utility installations at very competitive first costs.

EFCC cycles were examined during the 1960's by at least one gas turbine manufacturer. This manufacturer elected not to pursue the concept because one element of hardware was not then commercially available. The missing element, and only major new component required, was a high temperature heat exchanger. In order to achieve rated gas turbine efficiencies, turbine inlet temperatures approaching 2050F are required for contemporary gas turbines. Therefore the heat exchanger hot gas inlet temperature must be higher than metal tube technology was and still is capable of providing. Figure 4 presents a typical gas turbine performance curve and demonstrates the boundary that would be achievable with a metallic heat exchanger in an EFCC cycle. Due to limitations on operating temperature imposed by metallic heat exchangers, the turbine power output would be severely reduced. This limitation can be removed by the use of ceramic materials of construction in the heat exchanger.

Developments in the 1990s are expected to allow industrial base load turbine inlet temperatures of 2300F and above. These temperatures will require EFCC heat exchanger gas inlet temperatures of at least 2450F.

The metallic heat exchanger temperature deficiency can be corrected by supplementary firing a clean fuel directly in the cycle. Natural gas or #2 fuel oil could be used for this purpose. However, supplementary firing would adversely affect the economic viability of the concept, and, present logistics problems where natural gas or refined fuels are not readily available.A ceramic heat exchanger, capable of operating at 2200 to 2600F eliminates the need for supplementary firing a clean fuel and permits full optimization of the thermal efficiency and capacity potential of the turbine equipment.

ÇerHx CERAMIC HEAT EXCHANGER

Between 1975 and 1978, Hague developed a commercial ceramic heat exchanger to meet the needs of the steel forging industry for a thermal shock resistant, mechanically rugged high temperature recuperator. One such heat exchanger used as a furnace recuperator is shown if Figure 5.

In developing the CerHx heat exchanger, Hague began with an intensive ceramic tube development program. In the 1970's, tubes were made of calcium aluminate-bonded silicon carbide. These tubes provided the desired high temperature characteristics but were subject to oxidation and chemical attack in a relatively short time which resulted in tube failures. The tube life was unpredictable in some instances failures occurred within six months, while some of the tubes remained in service for five years and more.

During the late 1970's Hague mounted an effort to develop better tube materials. The steel and aluminum industry recuperator installations provided excellent field test facilities to evaluate tube configurations and materials. A second generation of tubes, made from oxynitride-bonded silicon carbide, was tested at temperatures of up to 2800F. The material was more predictable and in early 1983, this material became the standard tube material for Hague recuperators.

Since the introduction of the oxynitride-bonded tubes, unscheduled heat exchanger maintenance and parts replacement has been reported to be "virtually zero" by a user in the steel industry. Reports from the aluminum industry indicate tube life, of the inlet tube rows, of at least 1.5 years, under the most severe conditions. Aluminum recovery furnace applications, where flourides, chlorides and alkali oxide fluxes are used to purify molten aluminum, has demonstrated the resistance of the tube materials to extremely aggressive chemicals at high temperatures. Nevertheless, the life of carbide materials was limited and not totally satisfactory in the presence of the chemicals listed above as well as other impurities commonly found in the products of combustion of ash bearing fuels. Further the oxynitride material is permeable to air and difficult to seal. For these reasons, while satisfactory for low pressure industrial furnace applications, this material was not considered satisfactory by Hague for gas turbine applications.

As would be expected, the carbide tubes exhibited excellent resistance to thermal shock. Steel furnaces equipped with CerHx heat exchangers containing these tubes are repeatedly brought to steel forging temperature (2350F) from ambient temperatures in less than one hour without adversely affecting the thermal or mechanical characteristics of the tubes. The furnace service conditions are typically more severe than those anticipated in EFCC applications. Therefore, a compromise in thermal shock resistance was possible for the tubes applied to an EFCC.

In 1986, a new proprietary composit ceramic material was developed which, under both laboratory and operational tests, has demonstrated the necessary high temperature, thermal shock, and structural characteristics, as well as excellent chemical resistance to the impurities found in the products of combustion of ash bearing fuels.

The CerHx heat exchanger is a shell and tube design with ceramic tubes mounted in a steel frame which is sealed and insulated to contain the products of combustion. The clean gas turbine cycle air flows through the tubes and the products of combustion, containing the contaminants flows over the tubes. The air makes one pass through the heat exchanger while the products of combustion make two or three passes through the heat exchanger. A low pressure tube string arrangement which is similar, but, not identical to the high pressure version is shown in Figure 6. Pressurized air from the gas turbine cycle enters the cold header and makes one pass through the ceramic tubes, exiting into the hot header. The hot header is thermally insulated internally. On leaving the heat exchanger the hot air is ducted through internally insulated coaxial piping to the gas turbine.

The tube string arrangement selected for gas turbines was based on Hague's experience with other applications wherein the products of combustion were heavily laden with contaminants. The pressure integrity of each tube string is assured by means of spherical compression seals. Tube strings are composed of one or more tubes. Each tube string is capable of transferring sufficient thermal energy to generate approximately 30 KW of gas turbine shaft power.

The tube string configuration facilitates maintenance of the heat exchanger. One or more tubes can be replaced in a tube string in twenty minutes after the heat exchanger has cooled to a manageable level. The tube complement for a heat exchanger can be composed of a variety of tube materials from ceramics at the hot end to metal at the cold end. Provisions are made for soot blowing between tube strings. The design permits one or more combustion gas passes on the shell side. The passes are separated by interlocking ceramic elements held in place by each tube string. All materials of construction, including the ceramic heat exchanger wall linings were selected to provide maximum resistance to high temperature attack while providing the essential physical integrity during temperature transients to assure trouble free operation.

Since 1978 CerHx heat exchangers have successfully operated in both the aluminum and steel industries for approximately 600,000 hours at gas inlet temperatures of up to 2600F.

EFGT COST ASSESSMENTS

"Grass-roots" turn key cost assessments of the cycle were prepared by Hague, using the GE MS6001 gas turbine. These assessments resulted in a capital cost in the range of $1400 to $1800/kW for 55 MW commercial scale plants having projected heat rates under 9000 Btu/kWh.

More recently, preliminary comparative economics for 250 MW plant designs were prepared by Stone & Webster to compare Pulverized Coal (PC), Circulating Fluidized Bed (CFB), Integrated Gasification Combined Cycle (IGCC), and Externally Fired Combined Cycle (EFCC) shown in Figures 7, 8, 9, and 10 respectively. Process contingencies were utilized in an attempt to compensate for the differences in commercial development and/or operating experience. The Total Construction Costs and Total Operating and Maintenance Costs are shown in Tables 1 and 2 respectively. In each table EFCC shows a potential savings of more than 10 percent over the next best alternative. Again, please note that the IGCC and EFCC costs are estimates and are not based on actual operating experience.

Because of the importance to utilities of least-cost generation planning, the EFCC system would be of particular interest in those circumstances where the progressive generation concept is of value. Addition of coal capability to a natural gas fired combined cycle plant, initially designed to accommodate such a transition, would require coal storage and handling, coal combustion with in situ sulfur removal, a furnace cavity, ceramic heat exchanger and baghouse.

The EFCC concept will accomodate new gas turbines projected for the 90's. As turbine pressure ratios and inlet temperatures increase, the ability to separate the combustion gas stream from the turbine gas path, particularly when ash bearing fuels are involved, will have increasing value. Also, STIG gas turbines can be accomodated by the EFCC concept. When steam is used to improve the turbine cycle; the increase in mass flow and specific heat of the gas streams on both sides of the heat exchanger are also enhanced thereby similarly improving the performance of the heat exchanger. The EFSTIG (externally fired STIG cycle) is currently under evaluation at Hague with the collaboration of Stone & Webster.

MARKET INTEREST

Recent interest in EFCC by the utility, industrial, and government market sectors has been largely due to the cycles ability to provide;

- o Wide range of fuel flexibility
- o High plant efficiency
- o Small plant modular construction

Each market sector appears to have different fuel interests. The utility interest is in coal/lignite fuels as alternatives to oil and gas. Government interests at the municipal level are associated with refuse-derived fuels. Industrial interests are in biomass and process wastes for fuels.

The small plant modular construction aspect interest is in line with public utility commission interests for electric utility new generation planning:

- Smaller plant sizes
- Shorter schedules
- Improved plant efficiency
- Low project financing charges

Existing coal fired generation technologies (AFB, PC/FGD, IGCC, etc) have documented economies of scale and are normally considered in 200 MW increments or more. EFCC plants will be built more in line with conventional combined cycle plant sizes (50 to 250 MW). Similarly, the major components can be shop fabricated and quickly field erected, resulting in shorter overall schedules and reduced financing charges.

The small unit size and short construction schedule allow a shorter planning horizon and closer load growth accompanied by commensurate reduction of risk inherent in construction based upon long-term projections.

RECENT DEVELOPMENTS

The EFCC design has begun to attract nationwide attention in the United States. The following reflect some of the various interests which have been expressed during the last six months:

- Stone & Webster and Hague agreed to develop EFCC conceptual designs and demonstrate programs for coal, lignite, and refuse derived fuels.

- The Ninth International Coal Utilization and Transportation Conference (November 1986) included a presentation of "Externally Fired Gas Turbine Combined Cycle" as one of the significant emerging fuel technology options.

- Florida Power Corporation elected to take a leadership role in establishing an industry sponsor group for the purpose of supporting a phased development program designed to make EFCC a commercial generation planning option by 1990.

- Power Magazine (January, 1987) published an article on the development and scale up of "Solid Fuel-Fired Combined Cycles" indicating this cycle to be one of the significant developments for the power industry to watch.

- An industrial cogeneration project is under development utilizing a simple cycle gas turbine with steam injection for approximately 5 MW of electric power and 20 - 30 million BTU/Hr of process steam. The project is planned to initially fire natural gas but will be designed to utilize waste paper for at least 30 percent of the plant's energy requirements.

CONCLUSIONS

EFCC plants offer the potential for coal fired and other solid fuel power generation options with the following advantages:

- high efficiency
- fuel flexibility
- modular construction
- short project schedule
- low financing costs
- progressive generation
- compatible with evolving turbine technology

Successful completion of the two projects under development would offer both the utility and industrial sectors confirmation of the potential benefits of this cycle supported by continuous operation on two solid fuel alternatives.

250 MW POWER PLANT

TABLE 1 CAPITAL COST COMPARISON
(1985 CONSTANT DOLLARS X 1000)

	GCC	PC	AFB	EFGT
TOTAL DIRECT COST	$314,000	$286,800	$238,600	$201,200
INDIRECT COSTS	31,300	32,500	26,100	24,200
PROJECT CONTINGENCY	51,800	47,900	39,700	33,800
PROCESS CONTINGENCY	34,500	9,600	26,500	31,100
TOTAL PRESENT DAY COST	431,600	376,800	330,900	290,300
AFUDC	19,000	16,500	14,600	12,800
TOTAL PLANT INVESTMENT	$450,600	$393,300	$345,500	$303,100
$/KW	1800	1570	1380	1210
PERCENT VAR	+15	00	-12	-22

250 MW POWER PLANT

TABLE 2 OPERATING & MAINTENANCE COSTS

	PC	AFB	GCC	EFGT
FIXED O & M	6.052	4.945	6.400	4.468
VARIABLE O & M	2.594	2.119	2.743	1.915
CONSUMABLES	2.399	3.859	1.300	2.002
FUEL	15.779	15.469	15.175	13.730
TOTAL O & M COSTS (MILLS/KWH)	26.824	26.392	25.618	22.115
PERCENT VAR	00	-2	-5	-18

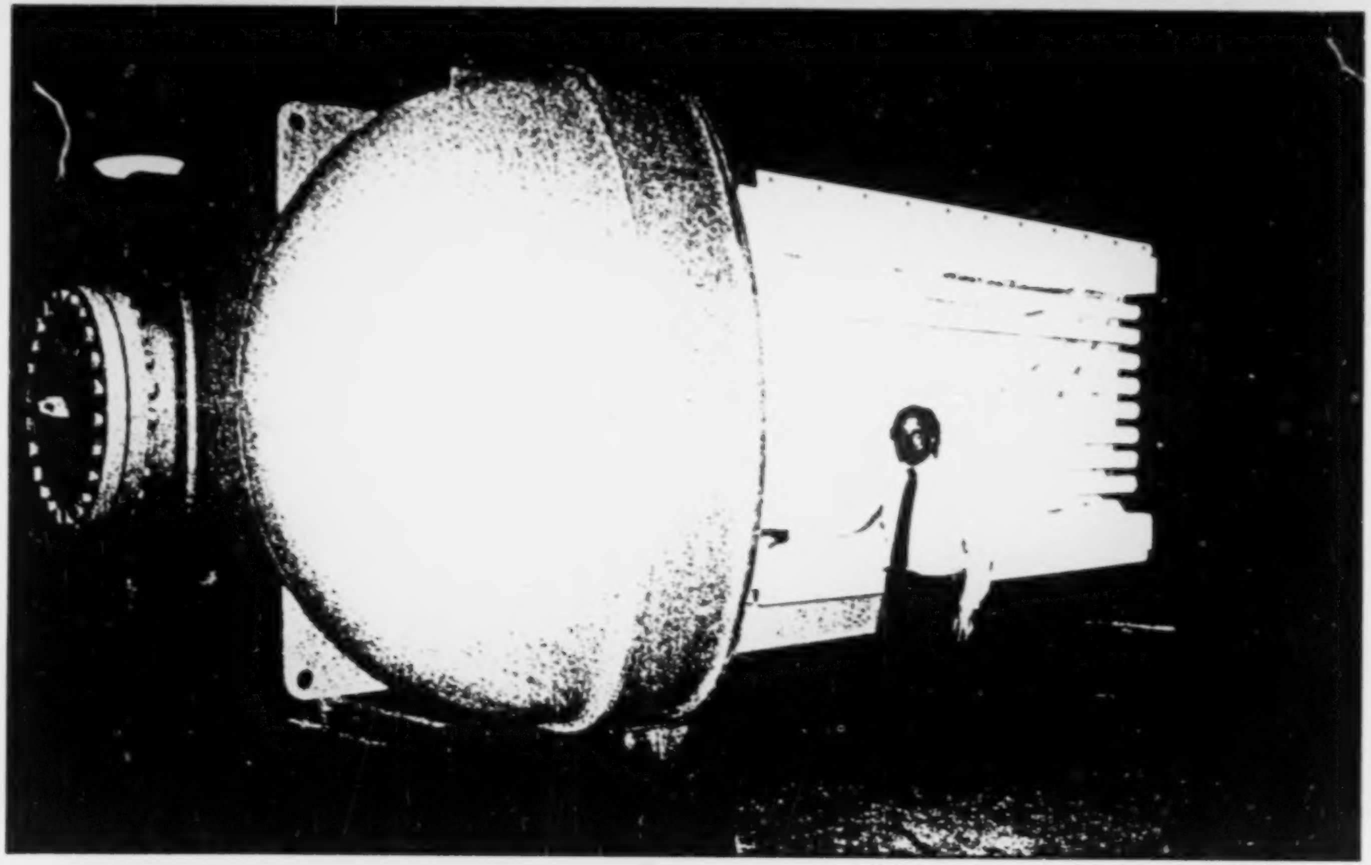


FIGURE 1 HAGUE INTERNATIONAL CerHx™
HEAT EXCHANGER

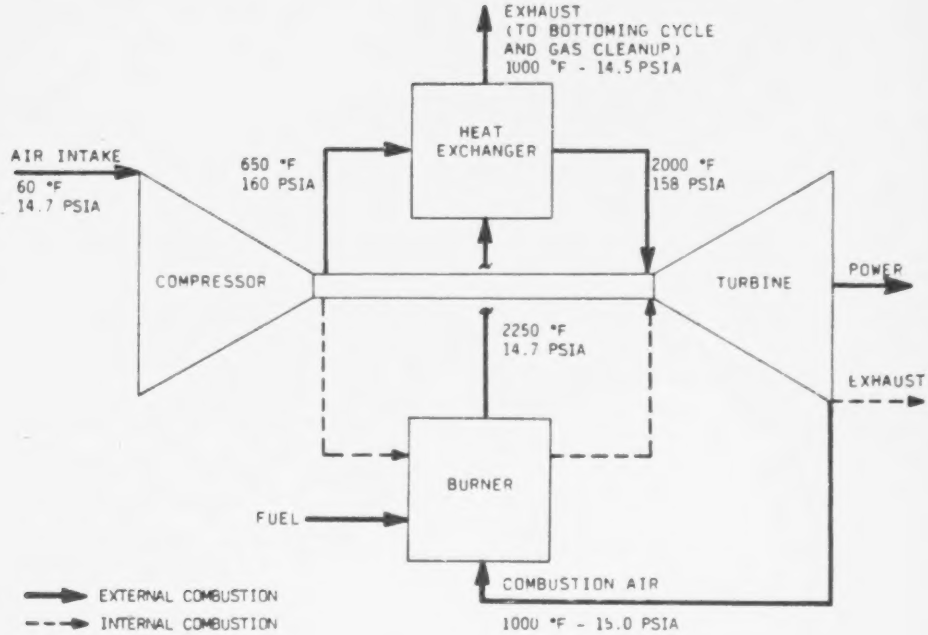
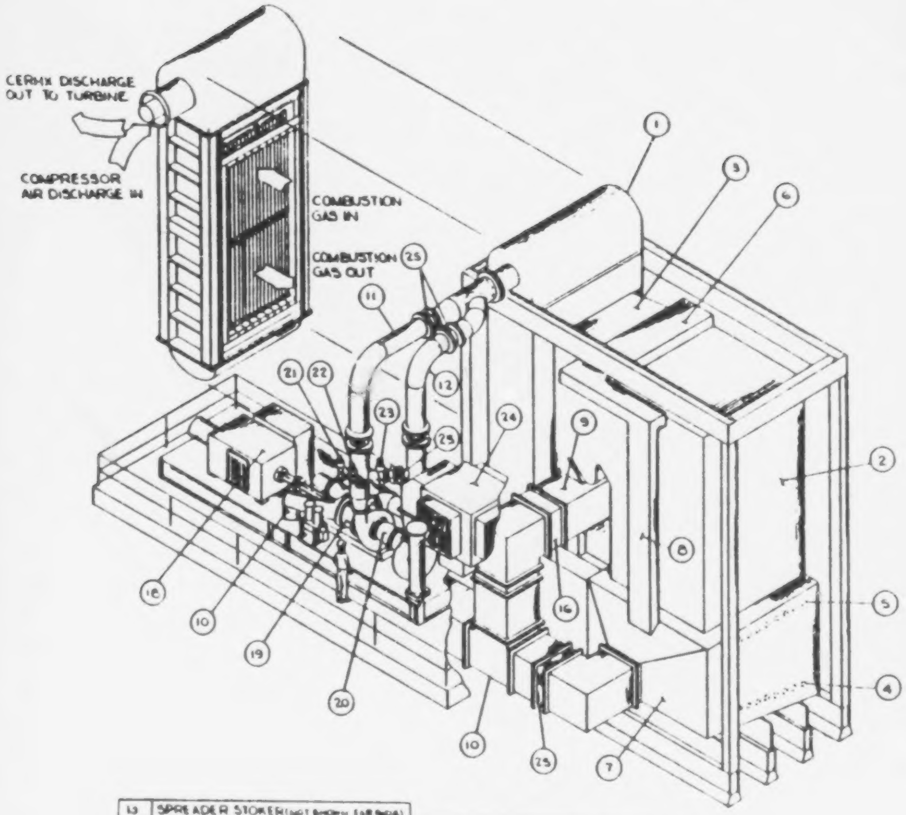

EXHAUST
(TO BOTTOMING CYCLE
AND GAS CLEANUP)
1000 °F - 14.5 PSIA
HEAT
EXCHANGER
AIR INTAKE
60 °F
14.7 PSIA
650 °F
160 PSIA
2000 °F
158 PSIA
COMPRESSOR
TURBINE
POWER
2250 °F
14.7 PSIA
EXHAUST
BURNER
FUEL
COMBUSTION AIR
1000 °F - 15.0 PSIA
EXTERNAL COMBUSTION
INTERNAL COMBUSTION

FIGURE 2 EXTERNALLY FIRED GAS TURBINE (EFGT) CYCLE


CERHX DISCHARGE OUT TO TURBINE
COMPRESSOR AIR DISCHARGE IN
COMBUSTION GAS IN
COMBUSTION GAS OUT
1
3
6
25
11
12
21
22
23
24
25
9
2
8
5
4
7
25
10
20
19
10
16
18

ITEM	DESCRIPTION	ITEM	DESCRIPTION
13	SPREADER STOKER (NOT SHOWN FAR SIDE)		
12	CERHX DISCHARGE AIR TO TURBINE	25	EXPANSION BELLOWS
11	COMPRESSOR DISCHARGE	24	INTAKE AIR FILTER
10	TURBINE EXHAUST	23	BYPASS CONTROL VALVE
9	DUCT TO HRSG (WHRSG)	22	SURGE CONTROL VALVE
8	TERTIARY COMBUSTION AIR DUCT	21	OVERSPEED DUMP VALVE
7	COMBUSTION AIR PLENUM	20	COMPRESSOR CASING
6	TERTIARY COMB AIR MATRIX	19	TURBINE CASING
5	SECONDARY COMB AIR NOZZLES	18	GENERATOR
4	PRIMARY COMB AIR NOZZLES	17	ASH REMOVAL AUGER (NOT SHOWN FAR SIDE)
3	SECONDARY COMBUSTION CHAMBER	16	BYPASS DAMPER
2	PRIMARY COMBUSTION CHAMBER	15	SIGHT PORT (NOT SHOWN FAR SIDE)
1	CERAMIC HEAT EXCHANGER	14	STARTING BURNER (NOT SHOWN FAR SIDE)

FIGURE 3 EFGT ISOMETRIC ARRANGEMENT

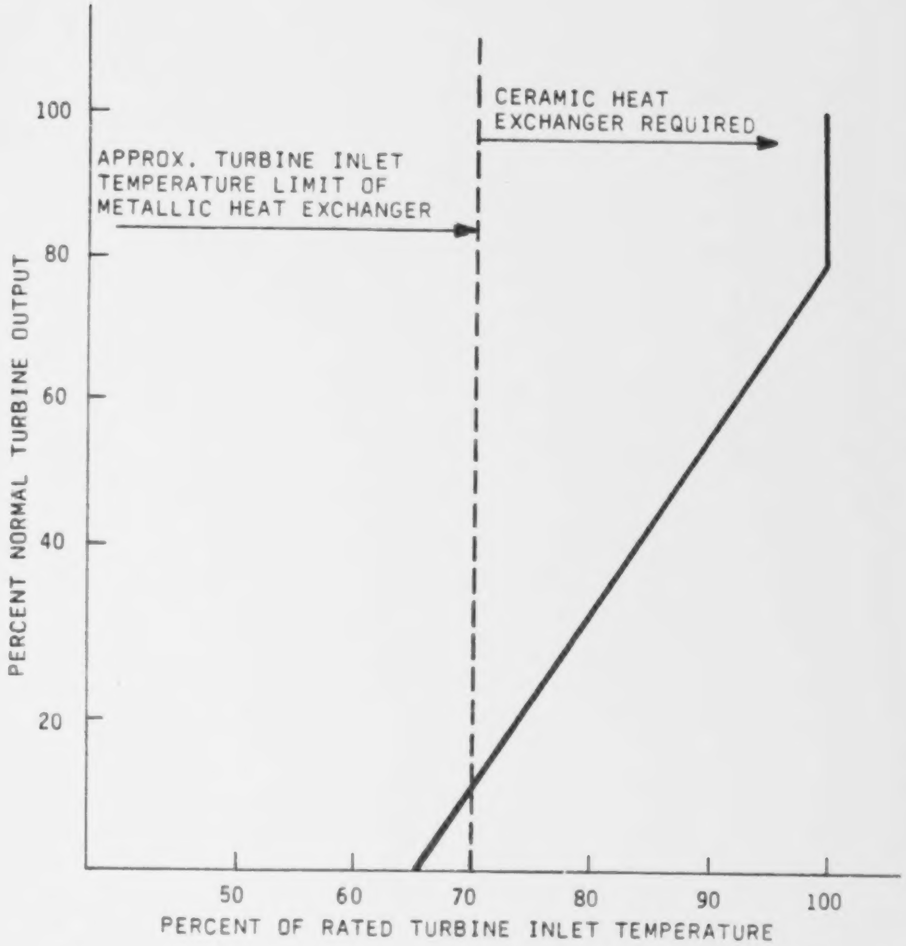


FIGURE 4 TYPICAL GAS TURBINE PERFORMANCE CURVE

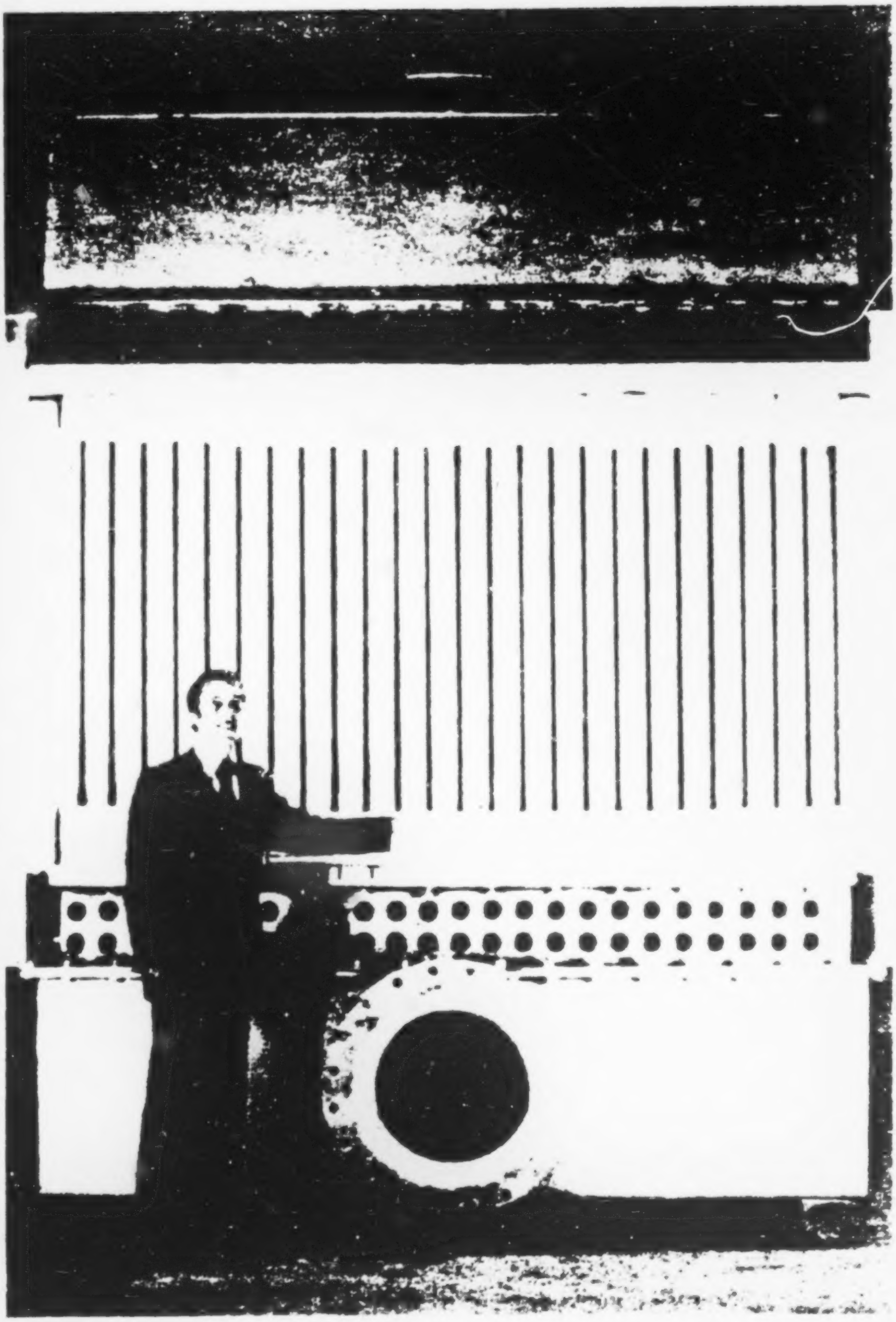
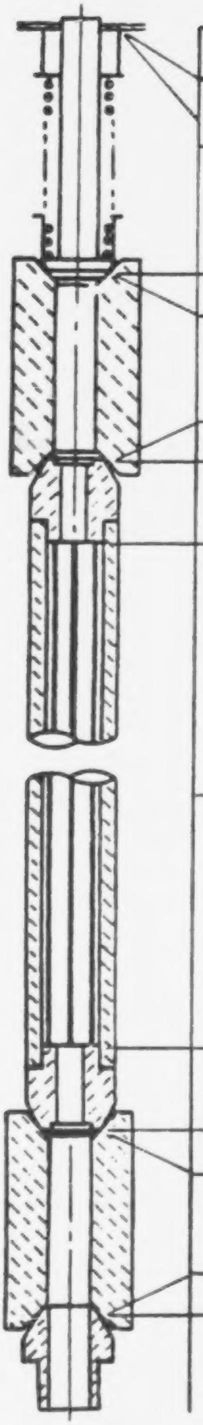


FIGURE 5 TYPICAL FURNACE RECUPERATOR



Description	Part #
Packing Gland 100B1009-2 and Gasket Ring 100A965	S52008
One (1) Spring Pack 200B986-2	S52004
One (1) Gasket 100B555	S52001
One (1) Hx Piece 100C1427	S71039
One (1) Gasket 100B555	S52001
One (1) Tube End 100B1273	S71042-3
One (1) 1.2 Meter Plain Tube 100B1272	S71029
Four (4) Turbulators 100B1280	S71026-28
One (1) Tube End 100B1273	S71042-3
One (1) Gasket 100B555	S52001
One (1) Hx Piece 100C1427	S71039
One (1) Gasket 100B555	S52001
One (1) Toadstool 100E1611	S71045
TOTALS	

FIGURE 6 TUBE STRING ASSEMBLY

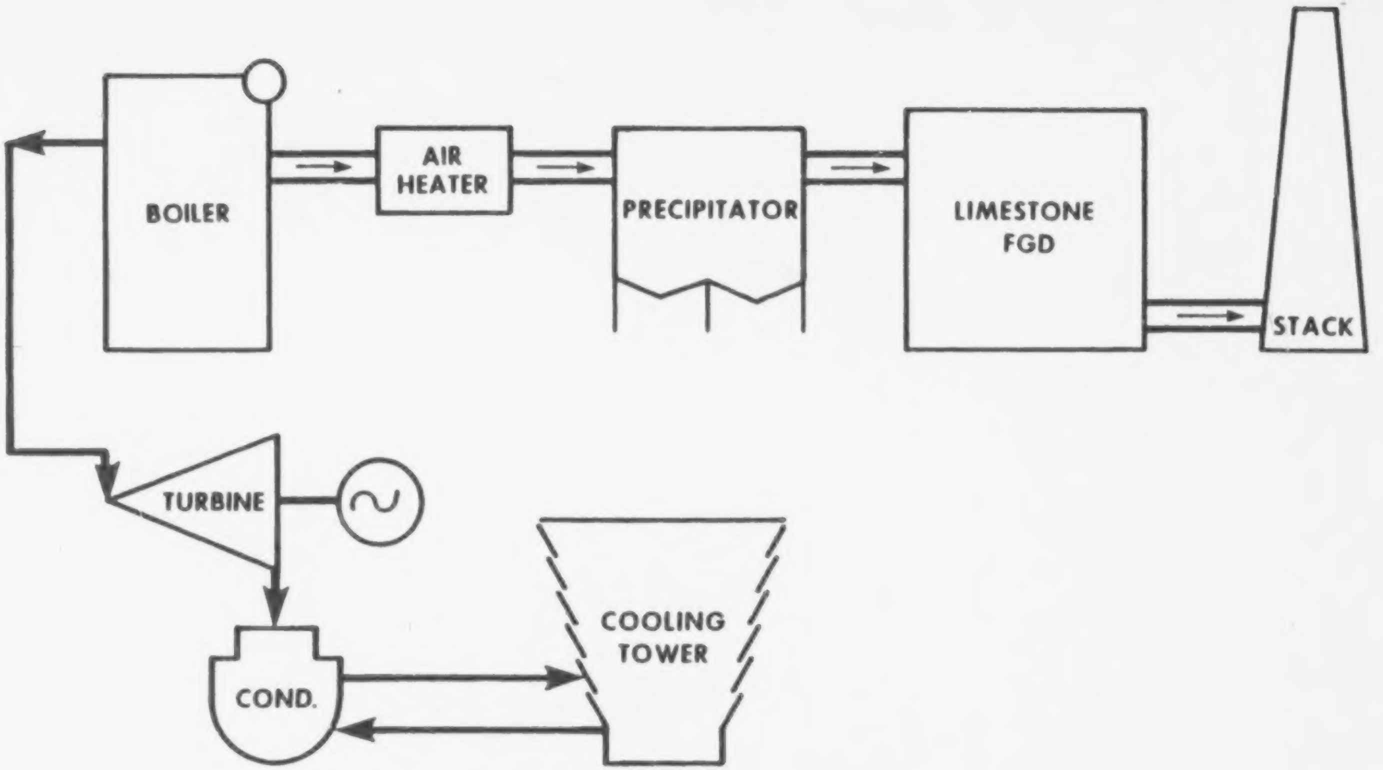

BOILER
AIR HEATER
PRECIPITATOR
LIMESTONE FGD
STACK
TURBINE
COND.
COOLING TOWER

FIGURE 7 PULVERIZED COAL FIRED BOILER
250 MW GENERATING UNIT

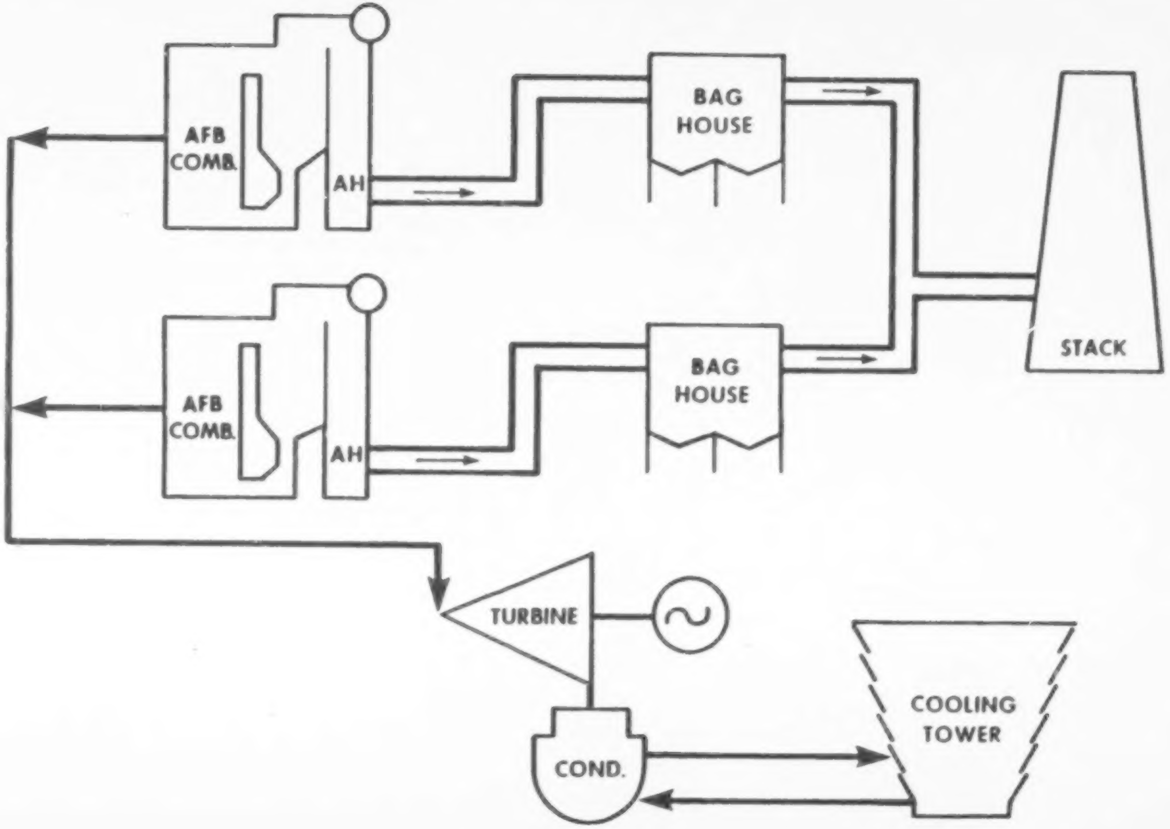

AFB
COMB.
AH
AFB
COMB.
AH
BAG
HOUSE
BAG
HOUSE
STACK
TURBINE
COND.
COOLING
TOWER

FIGURE 8 AFB COMBUSTOR
250 MW GENERATING UNIT

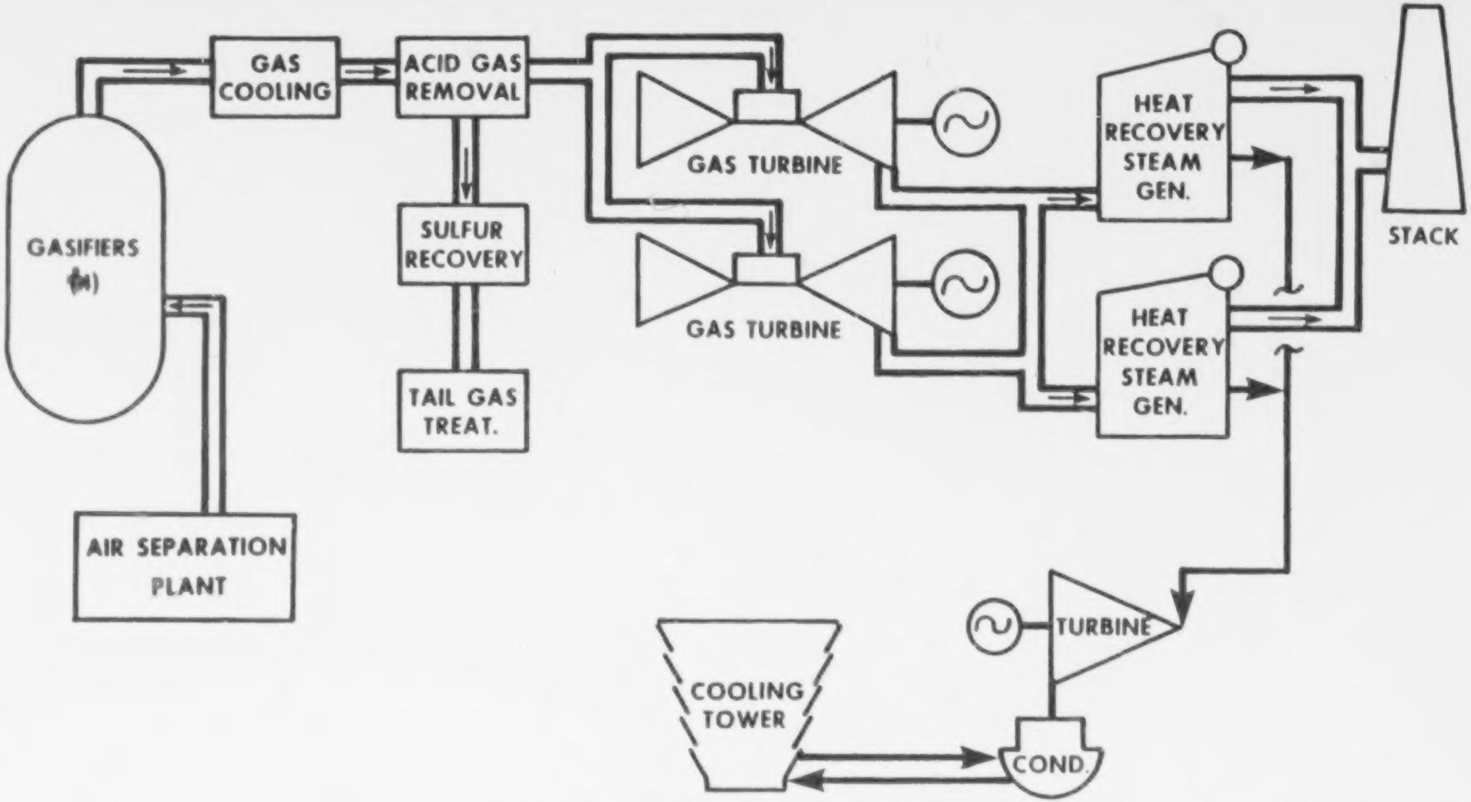

GASIFIERS
(4)
GAS COOLING
ACID GAS REMOVAL
SULFUR RECOVERY
TAIL GAS TREAT.
AIR SEPARATION PLANT
GAS TURBINE
GAS TURBINE
HEAT RECOVERY STEAM GEN.
HEAT RECOVERY STEAM GEN.
STACK
TURBINE
COND.
COOLING TOWER

FIGURE 9 COAL GASIFICATION-COMBINED CYCLE
250 MW GENERATING UNIT

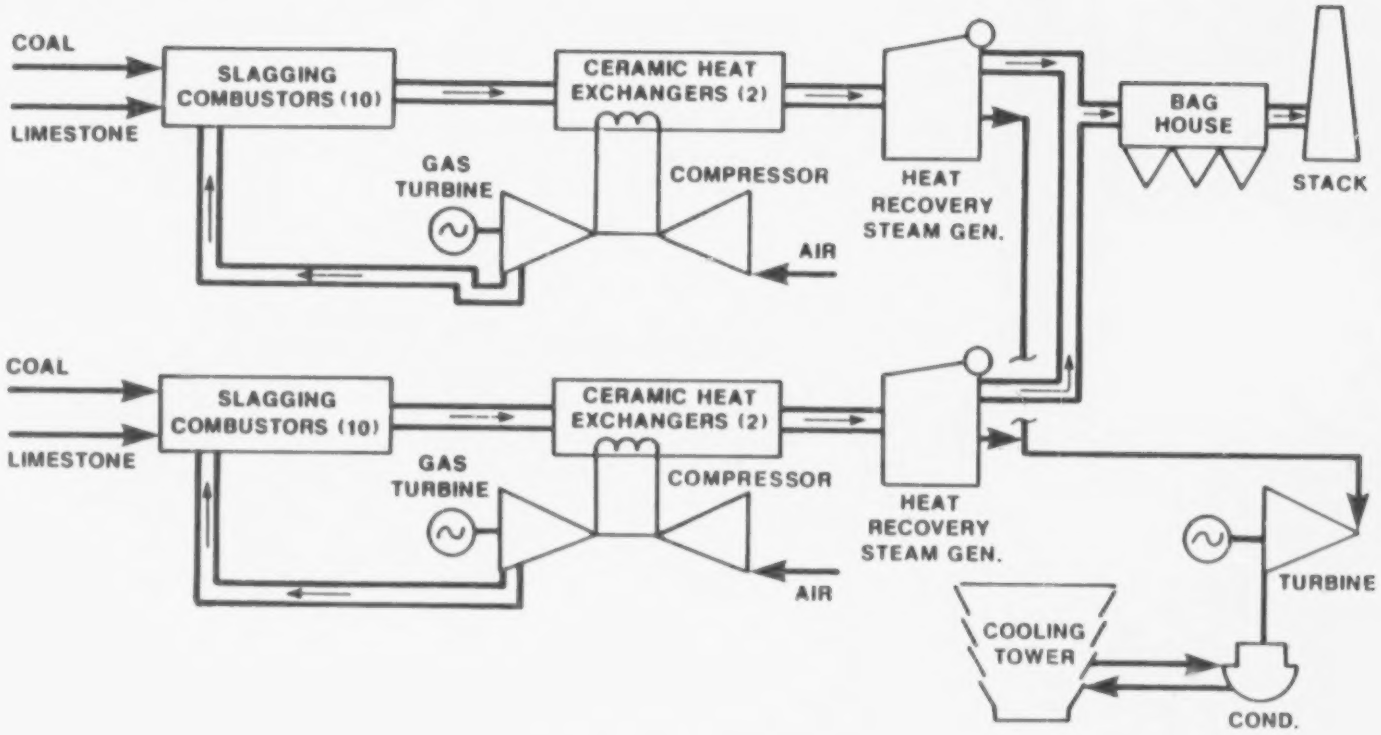

COAL
LIMESTONE
SLAGGING COMBUSTORS (10)
CERAMIC HEAT EXCHANGERS (2)
GAS TURBINE
COMPRESSOR
AIR
HEAT RECOVERY STEAM GEN.
BAG HOUSE
STACK
COAL
LIMESTONE
SLAGGING COMBUSTORS (10)
CERAMIC HEAT EXCHANGERS (2)
GAS TURBINE
COMPRESSOR
AIR
HEAT RECOVERY STEAM GEN.
TURBINE
COOLING TOWER
COND.

FIGURE 10 EXTERNALLY FIRED GAS TURBINE (EFGT)
COMBINED CYCLE
250 MW GENERATING UNIT

TESTIMONY OF DR. F. P. BOER
SENIOR VICE PRESIDENT
W. R. GRACE & CO.

BEFORE

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION

HEARING ON:

Emerging and available technologies
for the control of acid rain precursors.

9:30 a.m., Wednesday, March 4, 1987
Committee Hearing Room
406 Dirksen Senate Office Building

ORAL STATEMENT OF TESTIMONY

Dr. F. Peter Boer

March 4, 1987

Mr. Chairman, members of the Subcommittee, ladies and gentlemen, I appreciate your invitation to address the subject of Selective Catalytic Reduction. With me here this morning is Dr. Louis Hegedus, a research Vice President of W. R. Grace and an internationally recognized catalyst expert. My purpose this morning will be to tell you that a proven catalytic process is available to abate nitrogen oxide emissions from stationary sources, especially power plants, and that experienced firms such as W.R. Grace will make the commitment to supply the catalysts.

Let me give you some of the background that leads me to make this statement. W. R. Grace is not new to the catalyst business -- we have roots that go back to World War II, and we have built our business to the point where we are the leading worldwide supplier of catalysts. W.R. Grace also is by no means new to the business of controlling air pollution from nitrogen oxides. In fact, we entered the business when catalytic converters were mandated on American cars in the 1975 model year. Our Davison Chemical Division built a plant in Baltimore, and we are supplying catalyst for about 2,000,000 converters a year to Detroit.

To sustain our leadership position and to maintain our international competitiveness, W.R. Grace employs more than 200 scientists and technicians in the field of catalysis alone.

Ironically, the commercial development of power plant denitrification catalysts took place in Japan, for the simple reason that Japan was the first major country to mandate that this source of pollution be controlled. I say "ironically" because the origins of this technology can be traced to American laboratories. Japan's head start puts us and the rest of the world into a "catch-up" position.

There can be no doubt that the technical and economic performance of the SCR process has been proven in Japan, where more than 200 coal, oil, and gas-fired plants have retrofitted or original SCR units and are operating with minimal problems.

Our interest in SCR heightened in 1984, when the German public became alarmed by the "dying forest" issue, and the German government mandated control of NO_x emissions from both cars and power plants. As an immediate result, over 50 pilot plants have been installed and several commercial SCR facilities have been commissioned in Germany.

Grace researchers and engineers moved quickly, and in cooperation with our local partners, we developed the plans that led to the construction of a plant near Bonn. Ours is the first plant to go into operation in Germany. This plant is sized to provide catalyst for up to one-third of Germany's 46,000 megawatts of generating capacity requiring control. I have a sample with me and have included in your handout a German advertisement for our product. You will note in this ad that the R & D base for this business is right in our neighborhood at Grace's Washington Research Center.

A driving force in our decision to commercialize this technology in Germany was that it would prepare us to produce catalyst in the United States.

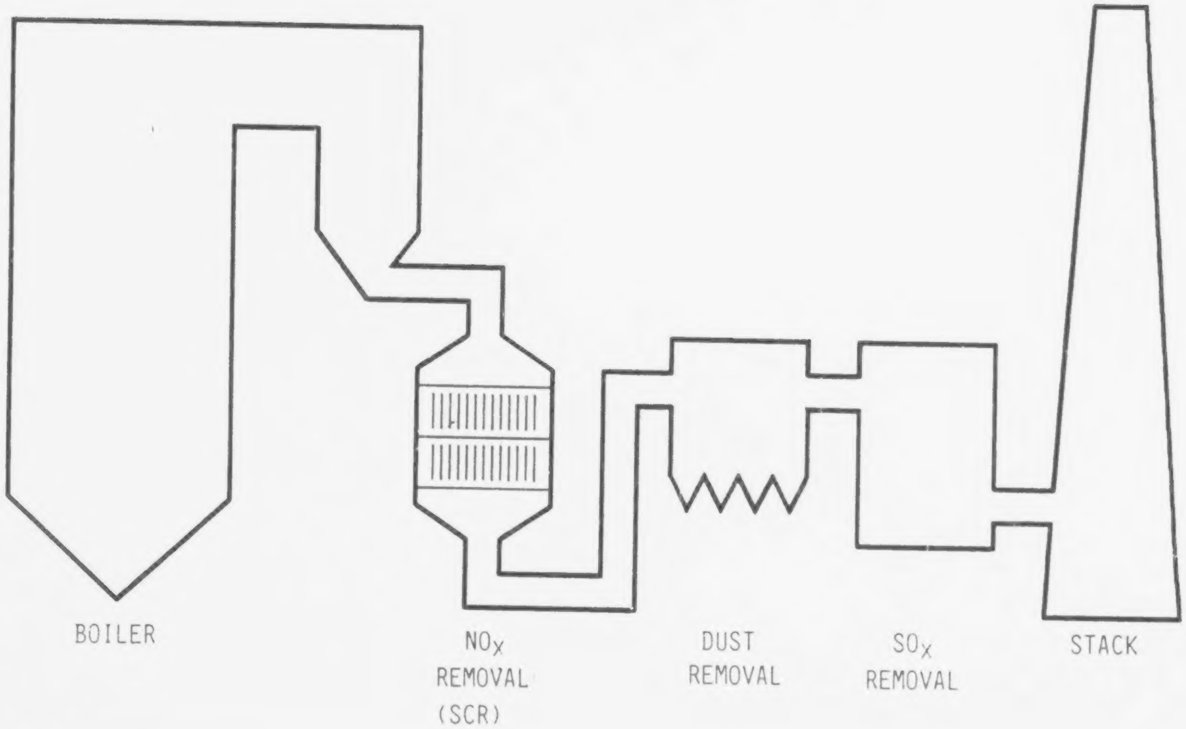
SCR catalysts are installed in large towers, which can be positioned after the boiler either in front of or behind a desox unit. They perform a simple and clean chemical reaction in which the NO_x is reacted with injected ammonia to form two harmless substances, nitrogen gas and water.

To be sure, there are technical issues in every installation, such as catalyst lifetimes and operating temperatures, but it is safe to say that in the vast majority of cases the SCR process will reliably remove 80 to 90% of the NO_x at a cost of 5 to 15 mils per kilowatt hour. It is our understanding that in Germany the costs are expected to be in the lower end of this range. Some of the most difficult remaining applications, such as the burning of dirty brown coals and operation in "wet-bottom" boilers, are on their way to being solved in Germany. These issues are not major problems in the U.S. Solving these problems and further reducing the cost of the catalyst are the jobs our researchers are tackling today.

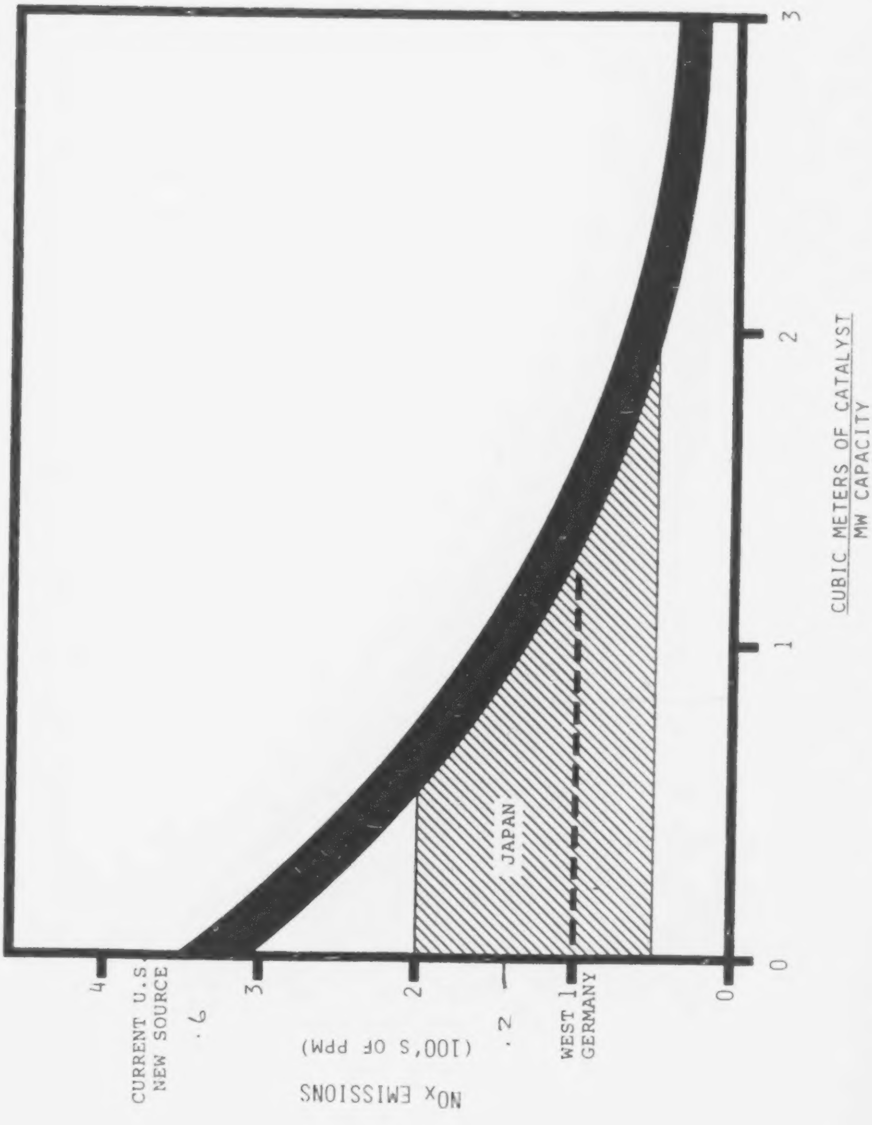
To summarize, then, SCR is not pie in the sky; it has been proven in hundreds of plants at a scale of up to 1000 megawatts. The decision to implement this technology is a matter of public policy involving difficult trade-offs of costs and benefits. When that decision is made, however, we in the U.S. catalyst industry will respond quickly, as we did with auto catalysts, to build the production facilities, make the product, and advance the technology.

SCR

"SELECTIVE CATALYTIC REDUCTION"


BOILER
NO_x REMOVAL (SCR)
DUST REMOVAL
SO_x REMOVAL
STACK

SCR CATALYST REQUIREMENTS



ANSWERS TO QUESTIONS POSED BY SENATOR MITCHELL

1. "What are the removal rates of the technology(ies) which you will describe? For sulfur dioxide? For oxides of nitrogen? How does this compare to other technologies?"

SCR does not remove sulfur dioxide. Typical nitrogen oxide removal rates are 60 to 90%. Other flue gas treatment technologies are not capable of achieving such high percentages of nitrogen oxide removal, as is shown below:

Technology	% Removal
Primary Combustion Control	15-40
Selective Non-Catalytic Reduction	30-60
SCR	60-90

2. "How long have these technologies been in use? At what scale? In what applications? Are they or will they soon be commercially available?"

Original applications of SCR technology for power plant emission control date from 1974 in Japan. To date, SCR technology has been applied to over 200 boilers there and is now being widely adopted in West Germany. The process is commercial on the scale of 1000 MW or beyond. Applications include gas-, oil-, and coal-fired boilers.

3. "What are the costs of these technologies? How does this cost compare to other technologies in use?"

Costs are summarized below:

	Capital Cost $/KW	Operating Cost mils/KWH
Primary Combustion Control	8-14(a)	0.2-0.4(a)
Selective Non-Catalytic Reduction	23-34	3-5
Selective Catalytic Reduction	54-98	5-15

(a) highly site-specific, may be higher

4. "Are these technologies capable of being retrofitted on plants currently in operation in the United States?"

Yes, the SCR technology can be readily retrofitted in the U.S. Such retrofits took place in Japan and are now taking place in Germany.

5. "What particular experiences have you or your company had with these technologies which makes you especially confident of them? What areas of concern remain for these technologies?"

W. R. Grace has established a joint venture in Germany which has built, and is operating, a plant to produce catalysts for SCR. In cooperation with German engineering companies, we have installed our catalyst into a number of German pilot plants. In addition, our joint venture is operating one of these pilot facilities. To support our German venture, we are conducting an R & D program in Columbia, Maryland which approaches an expenditure rate of $1 million per year. W. R. Grace has strong connections with Japanese and German catalyst, engineering, and utility companies, as well as members of academia.

The principal areas of concern with SCR catalysts are related to catalyst durability (poisoning on abrasion). These problems appear to have been satisfactorily solved for Japanese conditions, and are currently being tackled for German conditions. We expect the U.S. conditions to be closer tc those in Japan.

BACKGROUND STATEMENT ON NO_x CONTROL TECHNOLOGY BY SELECTIVE CATALYTIC REDUCTION

1. INTRODUCTION

W. R. Grace is the world's leading manufacturer of catalysts with major plants at Baltimore, Maryland; Lake Charles, Louisiana; Cincinnati, Ohio; Valleyfield, Quebec; and Worms, Germany. The company has over 200 scientists and technicians working on catalysis R & D. Grace is a major player in emission control catalysts, and was one of the first manufacturers of catalysts for automobile emission control. A plant dedicated to this application was put on stream in Baltimore in 1975; it currently produces catalysts for about 2 million vehicles per year.

Our interest in emission control has extended to other areas as well. In the U.S. and Europe, we sell a catalytic system for the reduction of volatile organic emissions from printing plant dryers. Under the scientific direction of Grace Research, Noxeram, a Grace-Feldmuehle venture, built a plant in West Germany to produce catalysts which control power plant NO_x emissions. This commercially proven catalytic technology is known as Selective Catalytic Reduction (SCR).

Our plant is located in Bergisch Gladbach and was the first to go into operation in Germany. The plant is sized to be able to provide catalyst for up to one-third of Germany's need for NO_x power plant emission control in 1991, which amounts to 46,000 MW of installed generating capacity. Indeed, one of the principal driving forces for our growing investment in SCR is our intention to become a leading SCR catalyst producer in the U.S.

The original ammonia injection process for NO_x control was invented in the U.S. about 20 years ago. However, the first commercial applications on power plants were in Japan, beginning in 1974, to meet the strict NO_x emission standards of that country. To date, SCR technology has been applied to over 200 units in Japan.(1) This technology is now being deployed in West Germany to meet recently enacted NO_x control regulations. Due to the strict emission standards and the short deadlines for compliance, SCR has been the process chosen in West Germany for most applications. Over 50 pilot plants have been installed(2) and several commercial SCR facilities have already been commissioned on German boilers. Once the mandated improvements are fully in effect, power plant NO_x emissions will have been reduced in West Germany by about 80%(3).

Interest in the SCR technology is gaining in the U.S. Limited SCR pilot plant testing was conducted in the early 1980's by the EPA and the Electric Power Research Institute (EPRI). In addition, Southern California Edison (SCE) has recently conducted an SCR demonstration at their Huntington Beach Power Station. In EPA-sponsored tests, a successful demonstration of SCR technology on U.S. coal at the 0.5-MW scale was made in 1980 at the Plant Mitchell Station of Georgia Power(4). This was followed in 1982 by EPRI-sponsored tests at the 2.5-MW Arapaho Emissions Test Facility on a coal-fired boiler owned by the Public Service of Colorado(5). Commercial demonstration of SCR in the U.S. on an oil-fired boiler began in 1982 at SCE's facility. By the end of 1985, it had logged over 18,000 hours of operating experience(6).

Widespread commercialization of SCR technology on power plants in the U.S. is awaiting stricter NO_x emission standards than those currently in effect. Areas of California currently have stringent NO_x standards. Here, SCR technology is used commercially to reduce NO_x from industrial boilers, refinery heaters, stationary engines, and gas turbines. However, the scale of operations is typically considerably smaller than required by electrical utilities.

2. TECHNOLOGY

The SCR process uses ammonia gas, injected into the flue gas to selectively reduce NO_x over the surfaces of a catalyst to molecular nitrogen and water. This reaction takes place in the range of 300°C to 400°C.

For coal-fired applications, Attachment 1 shows the two options generally available for installation of the catalytic reactor. In one case, the catalyst is placed directly after the economizer outlet. From the reactor, the flue gas flows to the inlet of the air preheater, with the electrostatic precipitator following the air preheater. This is known as the hot high-dust position. The catalyst is designed to withstand the full dust loading from the boiler.

In the second case, the catalytic reactor is placed downstream of the flue gas desulfurization process, away from the rest of the power plant equipment. This is called a cold low-dust position. This design may be more economical for a retrofit application if boiler space restrictions exist; however, this option must be weighed against an additional expenditure for the operation of a flue gas reheat system, which is required to raise the temperature to allow the catalyst to function.

The major equipment required for an SCR system are the catalytic reactors and the control and injection system for ammonia. Large fans are employed to overcome the additional pressure drop caused by the catalyst. Typically, about 0.75 MW of a 100-MW facility is needed to power these fans.

A typical SCR catalyst is composed of vanadium and tungsten oxides supported on a porous titanium dioxide carrier. The catalyst is in the form of a honeycomb (150-mm square by 1 m long). A number of variations have been developed to support these catalysts. In addition to the ceramic monoliths as produced by Grace, ceramic beads and metal plates have also found some applications. These catalyst elements are packed into a steel frame to form catalyst modules which are installed in several layers in the reactor. The gas flows downward vertically through channels of the honeycomb structure. A photograph of a honeycomb catalyst is shown in Attachment 2.

SCR units are generally designed to achieve 90% NOx removal and the facilities are guaranteed to remove 80%. At the same time, the oxidation of SO_2 and the discharge of unreacted ammonia are kept to a minimum by proper design of the catalyst. Unreacted ammonia is called ammonia slip. Ammonia slip is controlled for two reasons: to avoid its discharge to the atmosphere, and to avoid its combination with sulfur trioxide to solid ammonium bisulfate which could foul downstream equipment.

3. EFFECTIVENESS

SCR has been operating on Japanese utilities for 13 years in oil- and gas-fired units. After the first few years with some start-up problems, these facilities have operated in a trouble-free manner and, in fact, some gas-fired boilers have been operating with their initial catalyst charge for more than 10 years. Development of SCR for coal-fired boilers began in the late 1970's and is reaching the same quality of operation in Japan today(7).

In 1985, Ishikawajima-Harima Heavy Industries Co., Ltd. (IHI) published data detailing the performance of several SCR plants over a two-year period(8). These plants were located on coal-fired utilities in Japan. The data indicated that more than 80% denitrification efficiency was achieved with very low ammonia slip. Excellent performance, high efficiency and low ammonia slip were found over a wide range of the operating capacity. Plants have operated for more than 10,000 hours using many different kinds of coal.

4. U.S. APPLICABILITY OF TECHNOLOGY

An SCR unit can be installed on any gas-, oil-, or coal-fired facility in the United States. The technology is commercially practiced on all three boiler types in Japan today, and will be practiced on all three types of boilers in Germany. For coal-fired boilers, however, we expect that the introduction of the technology will require some pilot plant testing, as was the case in Germany. This will allow the U.S. engineering companies to develop a data base for SCR reactor sizing under U.S. conditions.

A number of design changes have been made in Germany to adapt Japan's technology to slagging and brown coal applications. In comparison with Germany, the U. S. obtains a smaller percentage of its power from slagging boilers, and has a smaller percentage of facilities operating with lignite. Nevertheless, the U.S. power industry will undoubtedly benefit from the process improvements being developed in Germany today.

5. ECONOMICS

SCR economics have been published by a number of organizations. The costs are often expressed in terms of total levelized costs which include fixed, variable, and capital charges. Generally, the results of studies done for U.S. locations indicate that the levelized costs of SCR facilities would be about one-third to two-thirds of the costs involved in operating conventional flue gas desulfurization units(9). Actual levelized SCR costs in Japan are currently about one-third the expense of flue gas desulfurization(3). As an example, data from a 1984 EPRI report(5) indicate that the levelized cost of SCR is 7.6-14.9 mils/kWh for low-sulfur coals and 5.7-11.1 mils/kWh for high-sulfur coals. The capital costs were reported to be in the range of \$60-\$98/kW for low-sulfur coal and \$54-\$83/kW for high-sulfur coal. The wide range of costs in the EPRI studies is due to the wide range of NO_x removal conditions considered. The lower costs apply to 60% removal from a 200-ppm NO_x flue gas stream, while the higher costs are for 90% NO_x removal from a flue gas stream containing 800 ppm NO_x.

6. AVAILABILITY

SCR catalysts for coal-fired applications are currently not manufactured in the U.S. Catalysts are available from Japan. Domestically produced SCR catalysts are available for oil- and gas-fired applications (process heaters, boilers, gas turbines). However, these catalysts are significantly different from those developed for coal-fired applications and cannot be used in coal-fired power plants.

As was the case in Germany, the availability of coal-fired SCR technology in the U.S. will be impacted by the enforceability of various patents; complex international licensing arrangements are to be expected. These problems were solved in Germany and will be solved in the U.S. In addition, it is likely that firms such as W. R. Grace will be able to develop technologies free of foreign patent claims. Several major U.S. engineering companies have affiliations with Japanese engineering companies and have access to SCR design technology(10).

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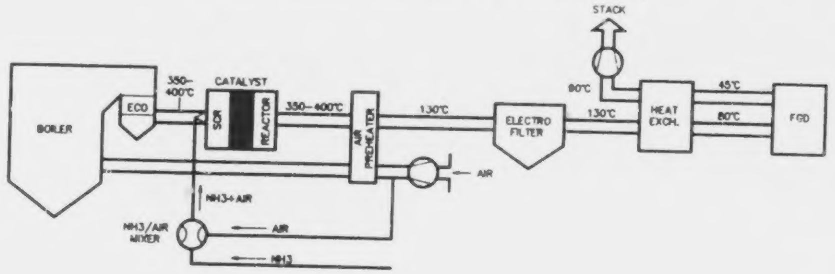
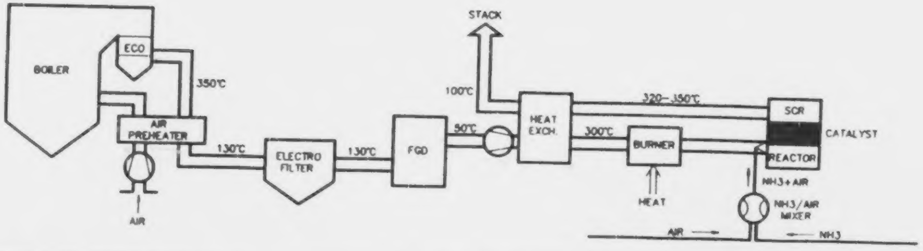
ATTACHMENT 1

"HIGH DUST" OPERATION:
SCR REACTOR BETWEEN ECONOMIZER AND AIR PREHEATER


STACK
BOILER
ECO
350-400°C
CATALYST
SCR
REACTOR
350-400°C
AIR PREHEATER
130°C
ELECTRO FILTER
90°C
130°C
HEAT EXCH.
45°C
80°C
FGD
AIR
NH3+AIR
NH3/AIR MIXER
AIR
NH3

"LOW DUST" OPERATION:
SCR REACTOR POST FGD


STACK
BOILER
ECO
350°C
AIR PREHEATER
AIR
130°C
ELECTRO FILTER
130°C
FGD
50°C
100°C
HEAT EXCH.
320-350°C
300°C
BURNER
HEAT
SCR
CATALYST
REACTOR
NH3+AIR
NH3/AIR MIXER
AIR
NH3

GRACE

F. Peter Boer, Senior Vice President

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May 20, 1987

Hon. George J. Mitchell
United States Senate
Committee on Environment and
Public Works
Washington, DC 20510-6175

Dear Senator Mitchell:

Thank you for your letter of May 8, 1987. I am very pleased to be able to answer Senator Lautenberg's questions, on which our position is quite clear.

1. "Do you feel the federal government is sufficiently fostering research and development of acid rain control technologies?

    -- Can the federal government do more to encourage such research and development?

    -- What modifications would you recommend?"

ANSWER

In light of the technologies already commercialized in Japan, West Germany, and the U.S., I feel that the federal government's existing programs in acid rain control are sufficient. At this point in time, industry needs government leadership in setting timing and standards for the reduction of emissions. Clearly defined goals for future emission limits are all the encouragement the pollution abatement industry requires from the government in order to begin to control acid rain. As when the federal government legislated controls on auto exhaust emissions, industry will respond quickly to build facilities, make products, and advance technologies to meet standards for control of power plant emissions.

2. "Which technologies control NO_x emission most effectively?

   -- Where are we in the development and use of these technologies?

   -- How effective are these technologies in NO_x removal?"

ANSWER

There are three commercially proven technology areas for the control of NO_x emissions: Primary Combustion Control, Selective Non-Catalytic Reduction, and Selective Catalytic Reduction. Of these, the processes that use Selective Catalytic Reduction (SCR) technology are the most efficient. SCR units, installed in the flue gas stream of a boiler, are generally designed to achieve 90% NO_x removal, and the facilities are guaranteed to remove 80%. Additional information on SCR technology is contained in the background material of my statement of March 4, 1987.

Sincerely yours,

CARBON FUELS CORPORATION

LEE G. MEYER
PRESIDENT & CEO

March 3, 1987

Mr. R. Brent Erickson
261 Dirkson Building
U.S. Senate
Washington, D.C. 20510

Re: Carbon Fuels Corporation's Testimony

Dear Brent:

As per our telephone conversation, enclosed is twenty (20) copies of Carbon Fuels Corporation's testimony for the hearing on "Available and Emerging Technologies for the Control of Acid Rain Precursors." I am also enclosing twenty Charfuel® brochures and a copy of the Morrison-Knudsen Engineers, Inc. Volume I/Executive Summary which was prepared for Carbon Fuels Corporation.

I appreciate the time and effort you are putting forth on our behalf and want to thank you for giving our testimony to the Subcommittee.

Sincerely,

Lee G. Meyer

Enclosures

LGM:sjh

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5105 DTC PARKWAY • ENGLEWOOD, COLORADO 80111 • (303) 770-7667

RESEARCH CENTER: P.O. BOX 3825 • LARAMIE, WY 82071 • 307/745-5045

TESTIMONY DELIVERED TO THE SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION OF THE SENATE COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

Hearing on

"Available and Emerging Technologies for the Control of Acid Rain Precursors"

Wednesday, March 4, 1987

STATEMENT OF TECHNOLOGY

There are two basic ways of reducing fuel pollutants. One is to accpet a polluting fuel at the combustion site and to remove pollutants during and after combustion. The second is to process fuel so that pollutants are removed prior to its delivery to the combustion site. The second method has advantages in reduction of capital costs, more efficient processing, and the opportunity to export products. It is the delivery of a clean burning, coal-derived fuel that is the technology of Carbon Fuels Corporation.

Carbon Fuels Corporation proposes a "clean coal technology" which contemplates the "refining of coal" in a short residence time, hydrodisproportionation process to produce Charfuel® fluidic fuel. This process is akin to refining petroleum, but uses domestic coal instead of foreign petroleum.

By-products of the process include methanol, BTX, and Naphtha. Nitrogen and sulfur pollutants are turned into elemental sulfur and ammonia and sold as by-products. Charfuel® is a competitive, uniform, high Btu/lb, environmental compliance char/pyrolysis oil mixture derived entirely from coal and capable of oil-type transportation, handling, blending and storage. Use of Charfuel® eliminates the need for scrubbers and reduces combustion NO_x.

The Charfuel® fluidic fuel eliminates the three major drawbacks associated with coal:

- transportation difficultites associated with a solid product
- non-uniform fuel
- pollution

Answer to Specific Questions Presented by the Committee

1. Our technology produces a compliance fuel which precludes the need for combustion pollutant removal. Specifically, during the Charfuel® process up to 95% of the organic sulfur can be removed from coal and up to 75% of the fuel nitrogen. Fine coal cleaning and/or washing may be required to remove pyritic sulfur and/or ash; however, since the Charfuel® product is fluidic, it can be blended so that eastern and western coals with various percentages of ash and pyritic sulfur can be used to form a compliance fuel. The slurry is a uniform, combusting material having high reactivity, ie., lower combustion temperatures, thereby minimizing the NO_x emission. Methanol which is produced simulataneously with

the Charfuel® process is also admixed with the slurry. As an "oxygenated fuel" this further reduces the NO_x emissions. It is believed that this compares extremely favorably both from a technical standpoint and an economic standpoint with other "combustion and/or fluegas" technologies. Specifically, other technologies are primarily concerned with the burning characteristics and/or removing flue gas streams. There is no technology which reduces the SO_x and NO_x emissions like the Charfuel® process.

2. The Charfuel® technology is in the commercialization stage. The hydrodisproportionation reactor has been run at 25 tons per day in a six year program. The rheology of the slurry has been studied during a study done for ARCO Pipeline Company based on materials derived from a Pittsburg Energy Technology Center test. Burn tests of char and pyrolysis liquids have been conducted. A 500 ton per day demonstration facility to produce Charfuel® slurry and to test burn is currently planned at the Dave Johnston power facility at Glenrock, Wyoming.

3. The cost of the technology is comparable to the cost of refining petroleum. Since this is a "value-added" process, the by-products such as naphtha, BTX, methanol, sulfur and ammonia provide sufficient revenues to more than compensate for the production cost of the fuel. Thus, Carbon Fuels Corporation plans to offer Charfuel® slurry at the "avoided cost" of coal, ie., at the same dollar/lb of steam in the

boiler as would be experienced with conventional coal. This cost compares very favorably with other technologies in use and has a wider application. For example, scrubbers do not remove NO_x and solid coal material can not be pipelined, tanker transported and the like. Therefore, there is considerable savings in power plant capital and operating costs as well as transport and storage. Moreover, Charfuel® slurry provides an excellent form for exporting U.S. coal into foreign markets. THIS FUEL CAN BE EXPORTED, HELPING OUR BALANCE OF TRADE.

4. Since Charfuel® is a uniform fuel, the only retrofitting required will be to make the burners capable of accepting a high Btu fluidic fuel. Carbon Fuels is currently working with Babcock & Wilcox and Foster Wheeler regarding the retrofitting of existing boilers. Part of the planned demonstration at the Glenrock, Wyoming plant is to pull "full power" on a 100 Megawatt retrofitted boiler.
5. Carbon Fuels Corporation has been working on the current technology for some six years. We have drawn on the experiences of many, many coal conversion applications in order to come up with the process which delivers Charfuel® slurry. The Company owns world-wide patents on the process and products. Ninety five (95%) percent of the plant, ie., other than the reactor, is commercially available, off-the-shelf technology. Therefore, Carbon Fuels Corporation is extremely confident of the success of the Glenrock

demonstration plant with only the reactor and pretreating system to be engineered on a commercial scale.

The Company currently has been granted $4 million of the Exxon Restitution Funds to retrofit the Dave Johnston plant boiler and Wyoming has just passed a "clean coal technology bill" which Carbon Fuels was instrumental in fostering that provides for $30 million for clean coal technology. Carbon Fuels has asked for $10 million of these funds. Carbon Fuels also is seeking federal funds for the methanol by-product process unit under the Canadian/United States accord, as well as DOE clean coal technology funds. Carbon Fuels intends to raise some $11 million in equity to finance the remainder of the demonstration project.

CHARFUEL® OF WYOMING, INC.
WYOMING COGENERATION PROJECT

PHASE	DESCRIPTION	ESTIMATED COST	FUNDING SOURCE	OBJECTIVES
I(A)	Design, construction and operation of a 500 TPD Charfuel® reactor	$ 16,000,000 + $4,000,000 contingency	State of Wyoming - $10,000,000 Private and/or Public Placement - $10,000,000	- optimize design criteria for a 10,000 TPD plant and demonstrate the technical feasibility of the reactor
I(B)	Design, retrofit and operation of a 100 MW power boiler	$ 4,000,000 + $1,000,000 contingency	Exxon Funds Loans - $ 2,000,000 Grants - $ 2,000,000 Private Placement - $ 1,000,000	- provide retrofit boiler design criteria - test burn the Charfuel® slurry
I(C)	Addition of a hydrotreater (may not be required)	$ 10,000,000	Debt or Public Offering-$10,000,000	- provide economically produced test burn Charfuel® slurry
		$ 35,000,000		
II	Design, construction and operation of a 10,000 TPD Charfuel® Commercial Plant	$450,000,000	Joint Venturers - $100-160,000,000 Public Offering - $10,000,000 Debt - $380-340,000,000	- provide a compliance, uniform, high Btu, fluidic fuel

TESTIMONY OF DAVID O. WEBB
SENIOR VICE PRESIDENT, POLICY AND REGULATORY AFFAIRS
GAS RESEARCH INSTITUTE
BEFORE THE ENVIRONMENT AND PUBLIC WORKS COMMITTEE
U.S. SENATE
MARCH 3, 1987

I appreciate the opportunity to submit testimony that outlines the Gas Research Institute's (GRI) recent research results on the use of natural gas to enhance cleanup of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from flue gases. Gas-enhanced emission control is one of the most promising near-term clean coal technologies, especially for retrofitting existing coal-fired boilers. It is critical for this committee to understand the potential and time frame for commercializing emerging gas-enhanced clean coal technologies to reduce SO_2 and NO_x emissions when it considers the relationship of proposed acid rain legislation and the DOE Clean Coal Technology Program. Otherwise, the committee might not be aware of these promising technologies and may inadvertently exclude their use in the legislation by establishing unrealistic compliance dates or by specifying the technology.

Congress has assigned a high priority to providing technology options for using our nation's abundant coal resources in an environmentally acceptable manner. Over the last two years, despite administration objections, Congress approved legislation appropriating $400 million for the Department of Energy (DOE) to demonstrate clean coal technologies through a cofunded program with industry. The private sector's response to DOE's request for statements of interest in demonstrating clean coal technologies clearly emphasizes the potential role of gas in clean coal technologies. Within the 176 private sector responses, the two largest technology categories were flue-gas cleanup (31 responses) and surface coal gasification (27 responses). In testimony last year before congressional committees on the clean coal program, DOE emphasized that the primary goal of emerging flue-gas cleanup technology is to provide low-cost approaches to NO_x and SO_2 emissions reduction at existing power plants. Therefore, it is encouraging that about one-fourth of the 51 proposals submitted to DOE in response to the Clean Coal RFP will use retrofit technologies to reduce SO_2 and NO_x emissions. Several of the proposals use gas in these applications. This is important since applications that use natural gas in combination with other technologies for flue-gas cleanup have the potential to provide one of the most cost-effective methods to use coal in existing utility and industrial boilers. Therefore, in the near term, the use of gas to enhance emissions control is an essential element of emerging integrated flue-gas cleanup systems. These systems offer the potential for early retrofit in many utility and large industrial boilers once they have been demonstrated on a full scale in operational utility systems.

Legislation must be sufficiently flexible to allow the introduction of emerging cost-effective gas-enhanced and other clean coal technologies as an option for industry in reducing NO_x and SO_2 emissions. Legislation that predetermines the technology options or establishes very near-term compliance schedules severely limits industry's ability to meet new emission standards and in many applications precludes the most cost-effective solutions, especially those that will be demonstrated under the DOE Clean Coal Technology Program. GRI urges the committee to consider these factors when it considers any acid rain legislation. Industry should not be limited in its use of natural gas in combination with other emerging clean coal technologies to produce the best and most cost-effective solutions.

GRI is an independent, not-for-profit scientific research organization that plans, manages, and develops financing for a cooperative research and development program for the mutual benefit of the gas industry and its present and future customers. The R&D program is implemented through contracts with research organizations, engineering and other professional service firms, universities, energy companies, and manufacturers.

Even though GRI is not a government contractor and does not accept federal funds, GRI cofunds and coordinates many of its research programs with DOE and other federal agencies including the Environmental Protection Agency (EPA). Over the last two years, GRI has cofunded research with the EPA on the use of gas to control NO_x emissions from coal. The results of this technology, generally referred to as "gas reburn," are very promising. Recently, GRI has agreed to provide cofunding for EPA's planned field demonstration of reburn technology which will be combined with sorbent injection technology to reduce SO_2 and NO_x emissions simultaneously. Also, GRI has pledged $10 million of cofunding for one of the nine projects selected under the DOE Clean Coal RFP. Three utilities will participate in this demonstration starting in mid-1987. If the results obtained in laboratory tests can be demonstrated successfully as a retrofit technology for industrial and utility boilers during the next three years, this technology would provide industry with an extremely cost-effective solution for combining NO_x and SO_2 emissions reduction. For this reason, I am submitting this testimony to make the committee members aware of these emerging technology options.

THE IMPORTANCE OF EMERGING TECHNOLOGIES

On April 24, 1984 the Secretary of DOE asked the Energy Research Advisory Board (ERAB) to convene a panel to assess the principal technologies for the clean use of coal. The ERAB panel completed its assessment in 1985. The committee should be aware of several of the panel's findings in its debate on any new legislation to reduce emissions from coal. These findings are:

1. Coal use in the U.S. is expected to continue to increase for most of the next 25 years.

2. The two major factors influencing this trend are the low price of coal compared with other fuels and the reduced contribution of nuclear power.

3. The number of specific coal-use situations is so large and diverse, and the specific problems are so site-specific that no generally applicable solution can be presented. This issue is even more difficult when applied to retrofit situations which represent the overwhelming majority of applications.

4. Direct combustion of coal will continue to represent over 90 percent of all coal use for the rest of the century and beyond.

5. Greater cooperation, particularly between DOE and EPA, and more coordinated funding can speed up completion of R&D programs that are urgently needed.

The ERAB panel made four specific recommendations in its report to DOE that clearly indicate the importance it assigns to emerging clean coal technologies

1. Early demonstration of retrofit technology is most urgent.

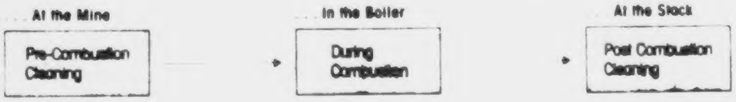
2. Limestone Injection Multistage Burner (LIMB) and improved Flue-Gas Desulfurization (FGD) should be top priorities. Aggressive pursuit of this target will make full deployment possible around 1990.

3. It is important to make sure that the high-sulfur coals that can be mined at a relatively low cost are given priority for the test work. This includes coals from areas such as Illinois and Indiana Nos. 5 and 6 seams, Kentucky Nos. 9 and 11 seams, and Ohio and West Virginia Pittsburgh seams.

4. The basic goal of the research will not be achieved unless we can apply new processes to the high-sulfur coals.

Coal Utilization

Opportunities for SOx/NOx Control



- Fine Grinding
- Dewatering (Low rank coals)
- Physical Cleaning
  and/or
- Chemical Cleaning

- Reconstitution
- Atmospheric Fluidized Bed
- Pressurized Fluidized Bed
- Low NOx Combustors
- Slagging Combustors

- Furnace Sorbent Injection Technologies
- Flue Gas Desulfurization (Scrubbers)
- Advanced SOx/NOx Scrubbing

Integrated Gasification Combined Cycle and Magnetohydrodynamics offer SOx/NOx control opportunities with differing techniques.

ROLE OF GAS IN CLEAN COAL TECHNOLOGIES

Federal policy has long overlooked the significant role natural gas can play in helping the nation use coal in an environmentally acceptable manner. Therefore, it is particularly encouraging to GRI and the gas industry that ERAB emphasized the urgency to demonstrate flue-gas cleanup for both NO_x control and to assist in SO_2 control in its report to DOE. In fact, for many near-term retrofit applications, gas used in combination with coal in both industrial and utility combustion systems has the potential to be the most cost-effective solution.

Natural gas is our nation's cleanest fossil fuel. Its combustion emits virtually no particulates, sulfur oxides, or reactive hydrocarbons, and it produces far lower emissions of nitrogen oxides and carbon monoxide per unit of energy than coal or oil. Gas is a domestic resource, and the gas supply outlook is excellent. The price of gas is attractive, and because users do not have to worry about onsite storage, the operating and maintenance costs are also lower. Used selectively, either alone or with other more polluting fuels, relatively small quantities of natural gas could contribute significantly to protecting our air quality in a least-cost manner. Given these factors, the competitive position of gas relative to other environmental control options should remain favorable. In addition, a million-mile pipeline and distribution network is already in place which extends to most utility and large industrial customers. Therefore, pollution control technology using gas can begin almost immediately.

Gas can be used in one combustion unit to offset the emissions from dirtier fuels, such as coal, in another unit; it can be used for simultaneous combustion of gas and coal in a single combustor; and it can be used to enhance flue-gas cleanup systems, particularly sorbent injection techniques to reduce SO_2 and in a reburn mode to reduce NO_x. Only natural gas offers this ability for one control technology to reduce several pollutants at the same time. Therefore, using gas as part of the overall approach to controlling pollutant emissions during coal combustion should become one central element of national energy policy.

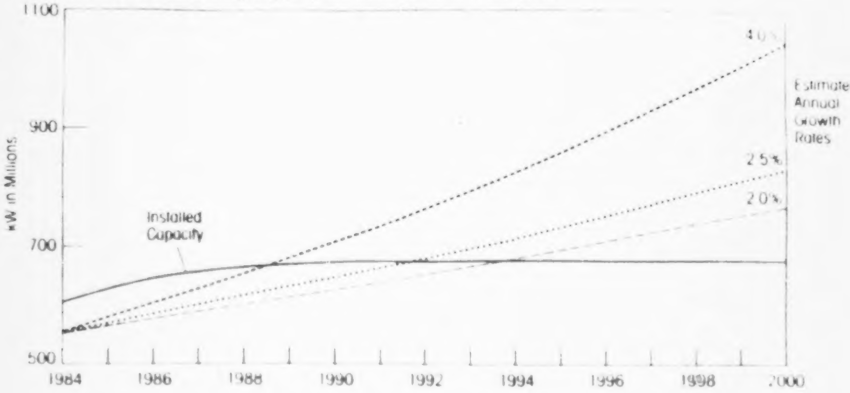
U.S. FUELS OUTLOOK

Another policy factor to consider in determining the importance of adopting flexible legislation standards and compliance deadlines that would allow emerging clean coal technologies to reduce industrial and utility boiler emissions is the extent to which the U.S. must rely on coal to meet its electric power generation demands between now and 2010. As a result of several major independent trends, the use of coal in the U.S. is expected to continue to increase at a reasonably steady pace for most of the next 25 years. The major influences of this trend are the continued economic advantage of coal compared with other fuels, its abundant supply, and the reduced contribution of nuclear power.

However, unless technology is demonstrated and introduced into the market to allow the U.S. to utilize its coal in an environmentally acceptable manner, the U.S. faces the possibility of regional shortage in electric generating capacity in the 1990s. The extent and timing of any specific shortages is very difficult to predict. Economic forecasts contained in DOE's National Energy Plans (NEP) have shifted from 4-percent-per-year growth in the economy in early 1970s NEPs to almost no growth forecasted in the NEPs issued in the late 1970s to about 2-percent-per-year growth in NEPs released in the early 1980s. To further complicate any projections, during the past decade, actual electricity growth has ranged from an increase of 7 percent per year to only 1.8 percent growth in 1985.

However, under any reasonable scenario of growth, electric consumption will increase. As stated by DOE Secretary Herrington in a speech on April 23, 1985, "Demand for electric power has continued to show a strong relationship with the growth of our economy." GRI's own modeling efforts indicate future electricity growth will be at a rate equal to approximately 85 percent of the rate of the economy's growth. Therefore, unless our economy is totally stagnant with resulting rapid increases in unemployment and misallocation of resources, electricity demand in the 1990s will continue to increase and will require the construction of new generating plants.

U.S. Electric Generating Capacity and Peak Demand, 1984-2000



If nuclear power does not make a quick resurgence to survive as a viable future U.S. energy option, coal is the major domestic energy option with sufficient long-term resources to fuel the majority of these power plants. This scenario becomes especially convincing when you consider that the U.S. holds one-quarter of the world's known coal reserves, and electricity use, even with all of the conservation due to higher energy prices and economic downturns, has grown by approximately 30 percent since 1973.

If there is one thing the energy crisis of the past 12 years has taught us, it is that uncertainty is the only certainty. Long-term energy forecasts have proven to be consistently wrong. We cannot make policy assumptions with any confidence regarding the direction of energy demand, production, and prices. The real interest rates are double the historical experience. Also, it must be recognized that the economics of many emerging energy technologies are driven by the price of world oil, and this price is not based on production costs. In other words, the typical utility executive must make major energy decisions in a very unstable and uncertain operating environment.

In this environment, the utility sector must not be restrained in choosing the technology options best suited to cost-effective emissions reduction. All technology options--including gas-enhanced coal combustion and flue-gas cleanup--must be available. If any legislation is passed, it can be cost-effective only if it provides the flexibility to allow the select use of gas and emerging clean coal technologies to be choices available to industry.

GAS-ENHANCED DRY SORBENT INJECTION AND REBURN

Concern over acid precipitation and anticipated acid deposition legislation has created an incentive for government and industry to develop more cost-effective technologies to control both sulfur and nitrogen oxides from coal and oil combustion, particularly from utility and large industrial boilers.

GRI and the EPA have been funding the Energy and Environmental Research Corporation (EERC) of Irvine, California, to develop reburn and dry sorbent injection technology to control SO_2 and NO_x emissions from coal and oil combustion. GRI's focus has been to examine control of NO_x and SO_2 emissions from coal combustion by incorporating two developing gas combustion technologies which can be applied individually or as an integrated element of a flue-gas cleanup system.

1. Reburn Technology. Use of natural gas as a reburning fuel to reduce NO_x emissions.

2. Sorbent Injection Technology. Use of natural gas to improve the capture efficiency of reactive sorbents for enhanced SO_2 reduction.

EPA provided $860,000 ($400,000 in FY 1983 and $460,000 in FY 1984) in coordinated funding for the project via its existing reburn/sorbent injection contract with EERC. GRI's project ($937,900), which began in April 1984, expands EPA's original focus on coal-fired reburning/sorbent injection at EERC to include an evaluation of the additional benefits (e.g., cost reduction, increased emissions control, boiler operation improvements, etc.) obtainable from the use of gas.

Sulfur oxides can be controlled by removing sulfur from the fuel or sulfur oxides from the products of combustion. However, current methods such as scrubbers or coal cleaning generally are capital intensive with high operating and maintenance costs, or they do not provide the necessary degree of SO_2 control.

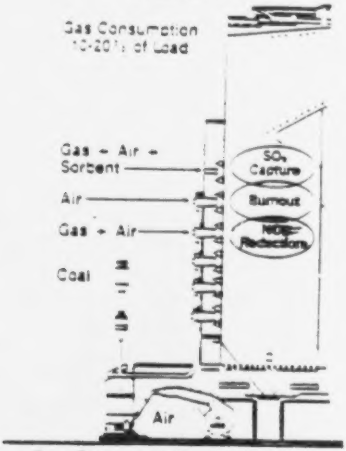
One of the more promising SO_2 control strategies is to inject calcium-based sorbents into the combustion chamber to capture the sulfur prior to the boiler outlet. This process was investigated in the late 1960s and was abandoned because it could not achieve the desired SO_2 control and also tended to create operational problems. Recently, there has been sufficient incentive to reexamine the limestone injection process (e.g., LIMB) as a cost-effective retrofit alternative for acid rain precursor control. The EPA's efforts in recent years have focused on the development of this technology for coal-fired boilers.

GRI's program with EERC has been to enhance the cost-effectiveness of this technology through the use of gas combustion technology. Gas may offer improved sorbent injection performance benefits by more effectively controlling the conditions at which limestone sorbent is calcined and mixed with the coal combustion flue gases; it may help to avoid coal-ash/sorbent interaction problems that decrease sorbent surface area; it can be used more effectively to optimize the temperature profile of the sulfation zone where sulfur capture occurs; and it reduces the amount of sorbent material needed.

Nitrogen oxide emissions are also considered, although historically to a lesser extent, as a contributing factor to acid deposition. The attention to NO_x as an acid deposition processor is increasing as scientific evidence tends to indicate that both SO_2 and NO_x are contributors. The formation of NO_x during the combustion of fossil fuels can be minimized by appropriate modification of the combustion process.

Recently, the Japanese have introduced a new NO_x control strategy which involves in-furnace NO_x reduction by creating a transient reducing zone within the boiler. EPA has been conducting research programs to evaluate the potential of this technique for application to U.S. boilers. The term "reburning" has been coined in the U.S. to refer to this process. When using gas as the reburn fuel. it appears that this technology is capable of reducing NO_x by approximately 50 to 60 percent beyond a boiler's current emission levels. The use of coal or oil as a reburning fuel may introduce operational problems because of poor carbon burnout resulting in a loss of efficiency as well as slagging in the platens or primary superheater region. The specific technical benefits of using gas as the reburning fuel are that gas can be broadly retrofitted to existing boilers and can be applied without the combustion problems associated with coal firing in upper boiler regions; gas allows lower exhaust NO_x emission levels to be achieved since it is nitrogen free; and gas avoids the presence of molten ash in the superheater boiler region, thereby minimizing slagging and fouling problems.

GAS APPLICATIONS
RESEARCH



Gas Enhanced Dry Sorbent Injection
Plus Gas Reburn -
SO_x/NO_x - Control

The use of gas technologies could also have an application in those instances where oil-fired boilers are being converted to coal-water slurry mixtures. Combustion systems which burn coal water slurries efficiently in boilers designed for oil rely upon efficient fuel-air mixing, precisely those conditions which promote the formation of nitrogen oxides. Consequently, any conversion could result in a considerable increase in both SO_2 and NO_x

emissions. An additional problem associated with conversion to coal-water slurries is the need to derate the unit to prevent excessive erosion in the convective sections. In some cases there are operational problems from unstable ignition. Natural gas used as a reburning fuel with or without sorbent injection can help solve these problems--pollutant emissions, unit derating, and flame stability.

Potential benefits of gas use are both environmental and economic. The development of more cost-effective SO_2, NO_x and combined SO_2/NO_x control technologies using gas would lower energy costs and improve air quality. The economic benefits are broad based and provide an alternative to high-cost flue-gas scrubbing technologies. In addition to the significant NO_x and SO_2 reductions, boiler operators may also realize substantial operating benefits (mitigation of boiler derating, particulate control, and reduction of availability problems, etc.) by implementing gas-enhanced reburn/sorbent injection techniques. Furthermore, the gas-enhanced technologies would increase our ability to use the nation's natural resources and would decrease our dependency on imported oil. The environmental payoff is a significantly reduced quantity of pollutants emitted by coal or oil burning.

Specific elements of the joint EPA/GRI research program that GRI funds are detailed on the following pages.

GAS REBURN--NO_x CONTROL

1. GRI's initial research goal is to develop gas reburn technology for NO_x control and to integrate gas reburn and boiler sorbent injection technologies for combined NO_x and SO_2 control.

2. The reburn research focus is to determine the optimum conditions and gas injection techniques to create fuel rich reburn regions for NO_x reduction.

3. Coal is burned as the primary fuel in the lower portion of the boiler under conventional conditions with the reburn gas (10 to 20 percent of total boiler fuel input) and, burnout air is injected in the higher sections of the boiler.

4. Research results to date from pilot scale testing indicate that NO_x emissions can be reduced significantly (greater than 50 percent) when small amounts of gas are fired in reburn fashion.

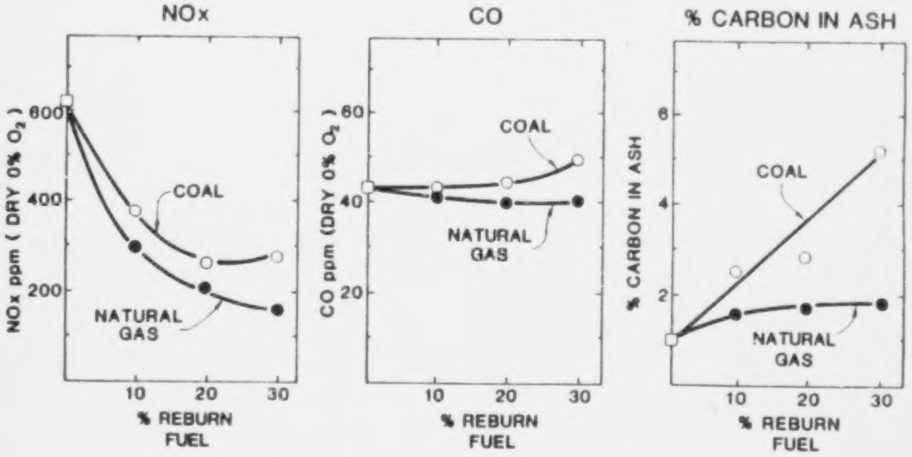
5. Compared to coal as the reburn fuel, gas is more effective in NO_x reduction; requires shorter reaction time; does not present operational problems such as carbon burnout, slagging, etc.; and simultaneously reduces SO_2 and particulate matter.

6. In addition to lower NO_x levels, gas reburn may be easier to retrofit than low-NO_x burners. For some boiler configurations low-NO_x burners are not commercially available.

The advantages of gas versus coal as a reburn fuel are illustrated below.

COMPARISON OF THE EFFECTIVENESS OF GAS AND COAL AS REBURN FUELS.

(PRIMARY FUEL : COAL ; SCALE : 10×10^6 Btu/hr)



GAS-ENHANCED DRY SORBENT INJECTION--SO_2

1. Simultaneously, GRI is funding research to use natural gas to enhance SO_2 control. This research is focused on both combining reburn technology with sorbent injection where there is a SO_2 reduction proportional to the amount of gas reburn fuel used and developing gas-enhanced sorbent preparation and injection techniques where gas is used to increase sorbent reactivity and utilization.

2. If successful, GRI's research will improve the cost-effectiveness of LIMB by reducing sorbent expenses and increasing SO_2 capture. More importantly, use of gas will lower the solids loading within the boiler and particulate control system.

3. Critical technical issues regarding sorbent injection are the quantity of sorbent material in boiler convective sections and entering electrostatic precipitators, calcination of sorbent to maximize surface area, protection of sorbent from sintering, and rapid mixing of sorbent with coal combustion flue gases within the temperature window (1750° to 2250°) for SO_2 capture.

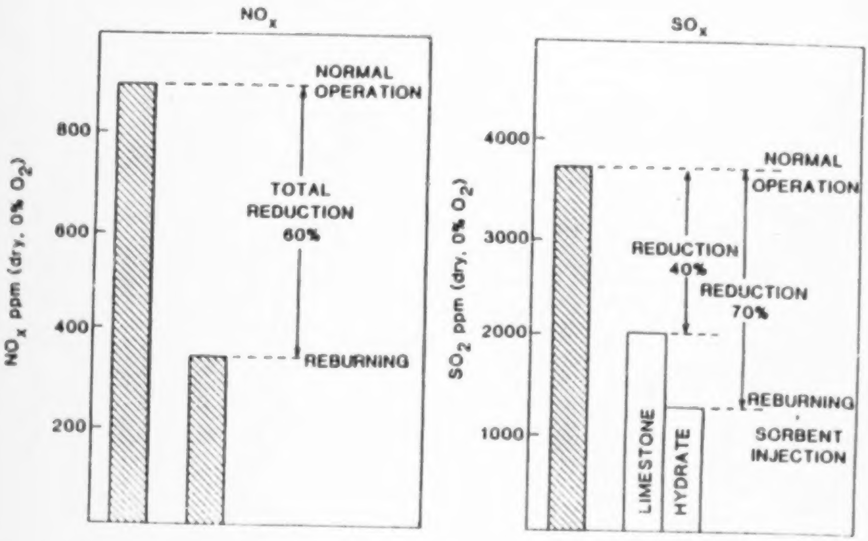
4. The relatively uniform composition and ease of handling makes natural gas the ideal fuel for resolving the critical technical issues and for enhancing the effectiveness of SO_2 removal.

5. Potential benefits of this research would be an improvement in the cost-effectiveness of LIMB technology and potentially broader applicability.

6. Total gas fuel requirements for combined gas-enhanced reburn and sorbent injection technologies are estimated to range from 15 to 20 percent of the total boiler fuel input.

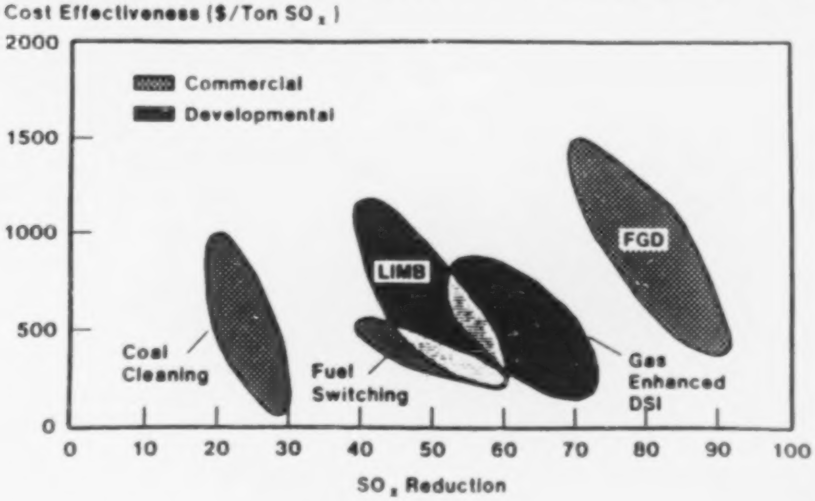
An illustration of the effectiveness of using natural gas to enhance flue-gas cleanup options is shown below.

GAS REBURNING-SORBENT INJECTION EFFECTIVENESS PRE-NSPS BOILER FIRING HIGH SULFUR COAL



The following figure is a graphic display of the range of DOE and EPA cost-effectiveness data available from the literature for each technology. The figure also shows the improved performance goals for gas-enhanced Dry Sorbent Injection (DSI) technology relative to LIMB. Of the technologies considered in the figure, only LIMB with low-NO$_x$ burners and gas-enhanced DSI plus gas reburn provide for both SO$_2$ and NO$_x$ control. Gas reburn achieves lower NO$_x$ levels. The basis for these cost comparisons are presented in the attached Tables 1 and 2.

RELATIVE COST EFFECTIVENESS OF ALTERNATIVE ACID PRECURSOR CONTROL STRATEGIES - SO_x



In conclusion, gas has the unique advantage of allowing the simultaneous application of reburn and sorbent injection technologies in the same boiler. GRI plans to commit $10 million over the next four years to cofund a demonstration of these gas-enhanced emissions control technologies in three operational utility boilers. The program, which the Energy and Environmental Research Corporation proposed in response to the DOE Clean Coal RFP, will demonstrate these gas technologies in the three primary boiler configurations the utilities use: sidewall-fired boiler, tangentially fired boiler, and cyclone-fired boiler.

OVERVIEW OF THE GR-SI DEMONSTRATION PROGRAM

The EERC proposal "Enhancing the Use of Eastern and Midwestern Coals by Gas Reburning-Sorbent Injection" was one of nine selected by DOE for demonstration in Phase I of the clean coal technology program. The estimated total cost of the program to demonstrate gas reburning-sorbent injection (GR-SI) is $30 million over three to four years. GRI will provide $10 million, and the

Department of Energy and Natural Resources of the State of Illinois will cofund $5 million. Also, EPRI has expressed interest in the program and may provide the use of certain equipment and facilities at no cost.

Three host sites (see Table 3) have agreed to participate in the program. These sites will provide full-scale, operational demonstrations in tangential, front-wall, and cyclone coal-fired boilers, which are typical of pre-NSPS designs. These types of units produce 12 million tons of SO_2 per year. Initial tests will be conducted using Kentucky and Illinois coals. Plans are being considered for testing other coals. Each host site will be tested for a range of conditions culminating in a one-year long-term evaluation. All data and test results will be compiled into a guideline manual which will be made available to industry.

Each host site will be considered separately based on its unique design parameters, operating history, and performance requirements. A field test will be conducted to quantify performance and emissions over the normal duty cycle. EERC will select a technology combination for each site which meets the emissions control and performance objectives at minimum total cost. Once these plans have been approved by DOE, the GR-SI hardware will be installed and tested prior to the beginning of the technology demonstration. The demonstration will include:

1. Optimization testing to determine the conditions which provide the best overall balance of performance.

2. Evaluation of alternate coals and sorbents to extend the data base on the technology. The tests will include the use of a cleaned coal.

3. Long-term evaluation of the GR-SI technology to assess impacts on boiler efficiency, slagging/fouling, carbon loss, convective pass erosion, auxiliary power consumption, precipitator performance, and ash disposal requirements as well as other site-specific factors.

4. Economic evaluation according to the EPRI Technology Guide (TAG) procedures.

5. Preparation of a Design Guideline Manual.

The objective of this project is to provide a comprehensive data base demonstrating the applicability of GR-SI when applied to pre-NSPS utility boilers and to promote commercialization. Rapid commercialization of GR-SI, once its performance has been verified, is possible because the infrastructure is already in place to apply the retrofit technology. A&E firms and boiler manufacturers will be in a position to commercialize the technology. This program will provide the technical basis. The major market for GR-SI is in the eastern and midwestern coal-producing states: Kentucky, Pennsylvania, West Virginia, Ohio, Illinois, and Indiana. These states have 47 percent of the total installed boiler capacity, or a little over 88,000 MW. GR-SI is a low-capital-cost technology, and it has a significant market niche for existing boilers in the 100 MW to 300 MW range. Therefore, GR-SI represents a potential near-term, cost-effective, environmentally acceptable solution to burning high-sulfur bituminous coal.

CONCLUSION

In conclusion, this GR-SI demonstration program has the potential to lead to the commercialization of a cost-effective, near-term retrofit acid rain precursor control technology. This technology will encourage the use of local coals and will provide the utilities with the flexibility to meet pollutant emission regulations with the fuel of choice at the least cost to the consumer.

Any future legislation that mandates reductions in emissions of SO_2 and NO_x from coal must contain the necessary flexibility and trade-offs of substituting NO_x reductions for partial credit against SO_2 reductions to allow industry to use these emerging technologies. Without this flexibility, years of federal and industry research efforts and taxpayer dollars will be wasted. More importantly, the most cost-effective solutions will not be available as options. This will increase the cost of electricity for all consumers.

Mr. Chairman, that completes my testimony. I sincerely appreciate the opportunity to submit this statement to your committee.

Table 1

BASES FOR ECONOMIC COMPARISONS OF SO_x and SO_x/NO_x RETROFIT CONTROL TECHNOLOGIES FOR POWER PLANTS

500 MW Rated Capacity -- Wall-Fired Boiler
Capacity Factor = 0.6
Coal Characterisitcs: 2.5% Sulfur
12.5% Ash
11,500 Btu/lb
15-Year Levelization Period
Flue Gas Desulfurization at 90% SO_x Removal
Natural Gas Reburn/Dry Sorbent Injection at 60% NO_x and 50% SO_x Control
15% Gas of Total Boiler Fuel
Gas Fuel Price Premiums of $1 and $2 per Million BTU Compared to Coal
EPRI Cost Guidelines
1986 Dollars

Table 2

COMPARISON OF COSTS OF SO_x and SO_x/NO_x RETROFIT CONTROL TECHNOLOGIES FOR 500 MW WALL-FIRED BOILER

	Investment Cost		Levelized Annual Cost		Emission Reduction			
					1000 Tons/Yr		Cost, $/Ton	
	$Million	$/KW	$Million/Yr	Mills/KWH	SO_x	NO_x	SO_x	SO_x/NO_x
Flue Gas Desulfurization	108	216	43	16	50	0	860	860
Natural Gas Reburn/ Dry Sorbent Injection								
$2/Million BTU Premium	24	48	26	10	28	7	925	740
$1/Million BTU Premium	22	45	21	8	28	7	750	600

Table 3

CHARACTERISTICS OF HOST SITES

GENERAL			
UTILITY	ILLINOIS POWER	CILCO	CWLP
STATION, UNIT	HENNEPIN, 1	EDWARDS, 1	LAKESIDE, 7
LOCATION: STATE	ILLINOIS	ILLINOIS	ILLINOIS
CAPACITY (MW)	80	117	40
BOILER			
FIRING CONFIGURATION	TANGENTIAL	FRONT WALL	CYCLONE
CAPACITY (10^3 lb/hr)	685	850	320
MANUFACTURER	CE	RILEY	B&W
PRECIPITATOR			
LOCATION	COLD SIDE	COLD SIDE	COLD SIDE
SIZE (SCA)	223	137	333-1000
MANUFACTURER	BUELL	AMERICAN STANDARD	SMIDTH
FUEL			
COAL TYPE	ILLINOIS, BIT	BLEND ILLINOIS, BIT KENTUCKY, BIT	ILLINOIS, BIT
SULFUR (%)	3-8	1.0	3.6
GAS AVAILABILITY	YES, 100%	4 MILES	ON SITE
EMISSIONS CONTROL APPROACH			
NO_x APPROACH	GAS REBURNING	GAS REBURNING	GAS REBURNING
CONTROL (%)	60	60	60
SO_2 APPROACH	UPPER FURNACE INJECTION	UPPER FURNACE INJECTION	DUCT INJECTION
CONTROL (%)	50	50	50
ESP ENHANCEMENT	HUMIDIFICATION	HUMIDIFICATION SO_3 INJECTION	NONE

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May 15, 1987

The Honorable George J. Mitchell
Chairman, Subcommittee on Environmental Protection
United States Senate
SH 408
Washington, D. C. 20510

Dear Senator Mitchell:

Re: Supplemental Testimony on NO_x and VOC Emissions Control for Stationary Sources

The Manufacturers of Emission Controls Association (MECA) wishes to again express its appreciation to the members of the Senate Subcommittee on Environmental Protection for the opportunity to present testimony on April 9, 1987 regarding motor vehicle emission control technologies. At the hearing, the Subcommittee invited MECA and others testifying to submit, for the record, additional information on control options to address this nation's air quality problems. In response to that request, we are pleased to provide the following information on the related subject of emission control technologies for stationary sources.

BACKGROUND & SUMMARY

Many of our companies have drawn on their extensive experience in the development and application of automotive catalyst technologies to develop and apply catalytic controls of volatile organic compounds (VOC), carbon monoxide (CO), and oxides of nitrogen (NO_x) emissions from stationary sources. The discussion below, which is presented on behalf of MECA's Stationary Source Control Committee, focuses on controls for NO_x and VOC -- two pollutants which scientists have concluded pose serious health and welfare risks and which are the target of further control in legislation pending before the Subcommittee.

We believe advanced catalytic control technology, which is available and being used around the world, could greatly reduce both NO_x and VOC emissions if it was widely applied to stationary sources in this country. These catalytic controls are reliable, currently used, and achieve emission reductions over 90% for NO_x and VOCs.

This technology will not receive widespread application, nor will the potential reductions be realized, unless specific emission control requirements are established. The success of the motor vehicle emission control program resulted from the specific standards established by Congress. In its efforts to develop legislation to address the serious air quality problems confronting this country, the Subcommittee may wish to draw on the mobile source experience and pursue similar statutory approaches for bringing about emission reductions from stationary sources.

NOx CONTROL

Japan and West Germany have established tough control measures to reduce the serious health and welfare threat posed by NO_x emissions. Most notably, these countries require stringent control of NO_x emissions from power plants. Catalyst technology, used to meet these requirements is achieving up to a 90% reduction in NO_x emissions from power plants.

In the United States, NO_x control efforts have focused on emissions from motor vehicles. For example, NO_x emissions from automobiles have been controlled since the 1970's, and today's vehicles, which have catalytic converters, remove over 75% of the potential NO_x emissions. By contrast, stationary sources have been required to achieve only modest control, most typically through modifications to the combustion process. At best, such measures result in reductions of 50 percent.

There are two important types of catalytic controls for stationary sources: non-selective catalytic reduction (NSCR) and selective catalyst reduction (SCR). Both of these techniques are highly efficient in controlling NO_x emissions, which are considered the most difficult conventional air pollutants to control.

Non-Selective Catalytic Reduction (NSCR)

Non-selective catalytic reduction (NSCR) is used on engines operating with a stoichiometric or rich fuel mixture. When NSCR is utilized, the CO formed in the engine combustion promotes the reduction of NO_x to nitrogen and carbon dioxide through a series of chemical reactions over a precious metal catalyst. NO_x control efficiencies of greater than 90% have been achieved. In engines that operate with stoichiometric air and fuel mixture, the catalyst oxidizes HC and CO emissions while still reducing NO_x. The catalyst assists the chemical reaction which converts NO_x, CO and HC to nitrogen, CO_2 and water.

The first uses of NSCR in the U.S. were in decolorization and abatement of tail gas in nitric acid producing plants in the mid-1960's and automobiles in the late 1970's, and this technology has now been applied to a variety of rich burning stationary engines. A simple control device can be used to automatically adjust the air fuel ratio so that NO_x control is optimized. Many of the installations using NSCR are in remote unmanned sites where an automatic controller is used to insure maximum catalyst performance under a variety of operating conditions.

Selective Catalytic Reduction (SCR)

Reduction of already oxidized nitrogen in an oxidizing atmosphere is a process called selective catalytic reduction (SCR) and involves the injection of ammonia into the post combustion regions of a boiler or engine whose exhausts contain significant amounts of oxygen. When ammonia is mixed with the combustion products at required temperatures, it reacts with the nitrogen oxides to form nitrogen and water, which are harmless. By using a special catalyst, the temperature required is significantly reduced and the efficiency of NO_x control is increased from approximately 50 percent to 90 percent.

SCR systems are used on stationary lean burn engines and have achieved 90% reductions in NO_x emissions. In the United States, its most predominate use is with gas turbines and refinery heaters. California and New Jersey have determined that SCR is the best available control technology for NO_x control of cogeneration units. Currently, over 18 cogeneration units in California are or will soon be equipped with SCR control systems. These cogeneration units typically utilize gas turbines to produce power and use the excess exhaust heat to make steam and/or additional electrical power. While SCR use on lean burn engines such as gas turbine engines is increasing, it is being employed on only a small fraction of the engines on which it could be utilized.

The largest potential use for SCR is to control NO_x emissions from power plants, and large industrial boilers including retrofit of existing major sources with control systems (see MECA's Statement on Retrofit of NO_x Emission Controls for Large Boilers attached). SCR can be used on gas- oil-and coal- fired boilers, and can achieve reductions of NO_x emissions in the range of 60-90%. The technology has proven effective in power plants up to 1,000 megawatts output in size.[1]

SCR technology, particularly in power plant application, has received only limited attention in the United States. Ironically, it was invented in the United States[2], however, it is being widely used in Japan and now increasingly in West Germany. In Japan, where NO_x emission standards were established for power plant emissions, SCR has been in commercial application since 1974. To date SCR technology has been applied to over 200 units in Japan where the systems are achieving control efficiencies of up to 90% with minimal operating difficulties.[3] SCR technology is now being deployed in West German to permit power plants to meet the recently-enacted NO_x control regulations designed to protect German forests from acid deposition. Over 50 pilot plants have been installed and several commercial SCR facilities have already been commissioned on German boilers. Once power plants are fully equipped with these control systems, power plant NO_x emissions are expected to be reduced by 80% in West Germany.[4] Both of these industrial nations have surpassed the United States in the control of NO_x emissions from power plants - again using U.S.-invented technology.

Issues Relating to Catalytic Control of NO_x

Opponents of the use of catalyst technology to control NO_x from major sources such as power plants raise a number of objections concerning the technology, including:

1. Cost
2. Operational problems including emission of unreacted ammonia ("ammonia slip")
3. Catalyst durability

These concerns certainly need to be addressed in employing SCR, but operating experience and continuing efforts to refine the technology has satisfactorily answered these concerns and show that these issues should not be road blocks to applying catalyst technology to major sources in this country.

Cost -- As noted above, catalytic control of NO_x emissions can achieve over a 90% reduction. This level of control is significantly greater than other control options, which typically achieve at best a 40-50% reduction. The higher cost is proportional and reasonable compared to the higher NO_x removal efficiency.

Operating cost of SCR have been estimated at 5 to 15 mils/kwh.[5] The experience in Germany suggests that the cost should be at the lower end of this range.[6] In addition, if NO_x emission standards were established which required the use of catalyst control technology, a major part of the technology development effort would focus on reducing the cost of control. Traditionally, as technologies have evolved and experience is gained, the cost of that technology has been reduced. For example, in Japan SCR costs have been considerably lowered and are currently about one-third that of flue gas desulfurization.[7]

Controlling NO_x emissions after combustion, heat exchange and power generation goes hand-in-hand with another important objective - conservation and the resulting reductions in fuel supply costs as well as CO_2 emissions. High combustion efficiency generally results in greater NO_x formation. Using SCR to control NO_x emissions after combustion permits the combustion process to be optimized for combustion efficiency.

Ammonia Slip and Other Operational Problems - In SCR operations, problems can arise when "slip" (unreacted) ammonia reacts with SO_3 in the flue gas to form ammonia sulfates which precipitate onto downstream equipment causing plugging and corrosion. In response to this potential problem, catalyst systems are designed not only to achieve NO_x removal efficiencies of up to 90%, but also to keep the oxidation of SO_2 and the discharge of unreacted ammonia at a minimum. For example, in 1985 Ishikawajima-Harima Heavy Industry Co., Ltd. reported on the performance of several SCR plants over a two-year period. These plants were located on coal-fired utilities in Japan. The data indicated that more than 80% NO_x control efficiency was achieved with very low ammonia slip. Excellent performance, high efficiency, and low ammonia slip were found over a wide range of operating capacities.[8]

Catalyst Durability -- SCR systems have been operating on Japanese utilities for thirteen years in oil and gas-fired units. The first few years saw some start-up problems. Since then, these facilities have operated without trouble and in fact some gas-fired boilers have been operating with their initial catalyst charge for more than ten years. Applications of SCR for coal-fired burners began in the late 1970's and is reaching equivalent level of development giving quality in-use performance in Japan today. Improving catalyst durability is a prime objective of current technology development efforts among our member companies and other throughout the world.

Legislative Initiatives to Control NO_x

Controlling NO_x emissions from power plants and large industrial boilers presents the greatest potential for NO_x reductions. The provisions in S.300 -- which would require major stationary sources of NO_x emissions to achieve emission reductions attained by technology demonstrated to be available for existing sources in any OECD country -- could be met with SCR and would result in significant reductions in NO_x emissions. While the requirement in S.321 that major fossil fuel fired steam generating units, including both electric utility and non-utility units meet a 0.6 pound per million BTU would result in some NO_x emission reductions, it would not achieve in the greatest NO_x reductions technologically feasible.

In those areas where additional NO_x control is determined to be necessary to help reduce ozone and/or acid deposition, a requirement that non-major stationary sources of NO_x conform to the most stringent BACT/LAER adopted for that type source anywhere in the U.S. could result in further significant reductions of NO_x.

CONTROL OF VOC EMISSIONS

The manufacture of many consumer products involves a processing step using organic compounds. In subsequent processing these compounds are removed in varying amounts and end up as emission by-product. Such volatile compounds may be solvents, unreacted feed stock, or decomposition products. A broad spectrum of volatile organic compounds (VOCs) are released into the atmosphere depending on the end product, process, and material used.

The most effective way to dispose of these VOC emissions is to burn or catalytically combust them. Catalytic oxidation is an advanced, highly efficient emission control combustion method. This technique can destroy 99% of the VOC's emitted. It is essentially a chemical oxidation process in which hydrocarbons are combined with oxygen at specific temperatures to yield carbon dioxide (CO_2) and water.

Not only is catalytic oxidation extremely effective in controlling VOC emissions, it is also an extremely flexible technology that can be applied to a variety of industrial processes. For example, it can remove hydrocarbons (HC) from exhausts which are below flammability limits and is capable of consuming HC to below a few parts per million concentration without utilizing additional fuel. Catalyst formulations and equipment can be matched to a particular source's application requirements. The technology can easily handle a mixture of different type VOCs, wide variations in air flow and wide variations in VOC concentrations. It is a simple and reliable technology, and when designed with an automatic system control, it does not need operating maintenance or labor.

Catalytic oxidation is basically a chemical process, and because of the catalyst, oxidation occurs at much lower temperatures than thermal incineration, thereby minimizing fuel and other costs. When VOCs are catalytically oxidized, heat is generated. This heat can be utilized in different ways to reduce the cost of operation. The heat resulting from catalytic oxidation of VOCs can be recovered or recycled to provide savings. The recovered heat may be used to sustain the oxidation reaction after initial start-up without the use of additional fuel. The purified air stream is passed through a recuperative heat exchanger before venting to the atmosphere. Incoming pollutant-laden exhaust is thereby preheated by heat exchange with the purified exhaust stream to either totally sustain the oxidation or, at the least, to reduce the amount of fuel required to keep the reaction at the operating temperature. The heat in the purified air stream may also be suitable for direct use as a recirculated, controlled atmosphere for a plant process, or it may also be recovered in a secondary heat exchanger or waste heat boiler. In some instances, the energy savings achieved by catalytic oxidation systems can actually be enough to reduce the energy consumption to levels lower than those used before the system was installed and thus even the investment in pollution controls can be recovered over time.

Oxidation catalysts have proven to be extremely durable in commercial applications. For example, some systems have operated continuously for as long as 10 years with little or no loss in control efficiency. In other cases, periodic maintenance which involves removing the catalyst bed, which, is an easily removable module, and blowing off or washing off residues, restores the catalyst bed to near original activity. Continuing improvements in catalyst design to enhance durability as well as the above- mentioned simple and economical methods for catalyst cleaning, will help insure continuous and extended service lives for catalyst control systems.

Oxidation catalysts are at present working successfully in hundreds of installations for a variety of industries around the world, including:

- Beverage Can Coating
- Solvent-Based Painting and Coating
- Printing and Laminating Processes
- Paint Finishings and Baking Systems
- Coil Coating and Metal Decorating
- Food, Tobacco, and Pharmaceutical Processing
- Pulp and Paper Processing
- Chemical and Petroleum Processing Industry
- Fabric Coating
- Wire Enamelling

Catalyst systems, however, are only being utilized on a fraction of the above sources to which they could be applied.

Legislative Initiatives to Control VOC Emissions

Comprehensive legislation to address VOC emissions from stationary sources is not currently before the Subcommittee. Nevertheless, we recognize that the issue of stationary source control of VOC emissions, a precursor to ozone, undoubtedly will be considered by the Subcommittee in the context of addressing the widespread ozone non-attainment problem. We would be pleased to comment on legislation that may be introduced relating to VOC controls. In the interim, we offer some general comments.

The levels of VOC emission reductions actually achieved in non-attainment areas, we believe, will be directly related not only to the stringency, but the specificity to which Clean Air Act amendments set out the control requirements. With this fact in mind, the Committee may wish to consider setting specific percent reductions for major existing, new and modified stationary sources of VOC emissions. Catalytic controls are quite capable of reducing VOC emissions by more than 90% without increasing NO_x emissions which occurs with high temperature thermal incineration. For those sources to which catalyst technology can be applied, and to which such control is necessary to achieve attainment with the ozone standard, a 90% reduction requirement would be an effective control strategy. In lieu of, or perhaps in conjunction with a percent reduction requirement, a legislative provision specifying that where such control is necessary to achieve attainment, sources would be required to conform to the most stringent RACT (for existing sources) or LAER (for new or modified sources) that has been adopted anywhere in the nation would be a technologically feasible means of achieving significant reductions of VOC emissions.

CONCLUSION

Control technologies which have evolved in part from the development and application of the automotive catalysts are available and offer considerable promise for significant reductions in VOC and NO_x emissions. As the Subcommittee continues the difficult task of formulating legislative solutions to address this nation's serious air quality problems, we would be pleased to provide additional information concerning the capabilities of these technologies.

Sincerely,

Bruce I Bertelsen

Bruce I. Bertelsen
Executive Director

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FOOTNOTES

1. Testimony of Dr. F. P. Boer, Senior Vice President, W.R. Grace & Co. before the Committee on Environment and Public Works, Subcommittee on Environmental Protection, March 3, 1987, p.3.

2. 1957 Application, U. S. Patent No. 2975025, issued 1961.

3. J. Ando, C.B. Sedman, "Status of Acid Rain and SO_2 and NO_x Abatement Technology in Japan", EPA-EPRI Tenth Symposium on Flue Gas Desulfurization, Atlanta, Georgia, Nov. 1986.

4. W. Ellison, "Assessment of SO_2/NO_x Emission Control Technology in Europe", EPA-EPRI Tenth Symposium on Flue Gas Desulfurization, Atlanta, Georgia, Nov. 1986.

5. Boer, Supra, Attachment, p. 2.

6. Id. at 3.

7. Chou University (Tokyo, Japan), "Recent Developments in SO_2 and NO_x Abatement Technology for Stationary Sources in Japan," September 1985, at 7-9.

8. H. Aoki, T. Suzuki, R. Ishimoto, "Introduction of IHI-Dentrification System for Coal-Fired Steam Generators", 1985 Joint EPA-EPRI Symposium on Stationary Combustion NO_x Control, Boston, Massachusetts, May 1985.

ACID RAIN CONTROL TECHNOLOGIES

Clean Coal and the United States and Canada Acid Rain Envoys' Report

WEDNESDAY, MARCH 11, 1987

U.S. Senate,
Committee on Environment and Public Works,
Subcommittee on Environmental Protection,
Washington, DC.

The subcommittee met, pursuant to notice, at 9:30 a.m., in Room SD-406, Dirksen Senate Office Building, Hon. George J. Mitchell (chairman of the subcommittee) presiding.

Present: Senators Mitchell, Graham, Lautenberg, Baucus, Chafee, Stafford, Durenberger, Pressler, and Simpson.

OPENING STATEMENT OF HON. GEORGE J. MITCHELL, U.S. SENATOR FROM THE STATE OF MAINE

Senator Mitchell. Good morning, ladies and gentlemen.

The hearing will come to order.

Last year, the U.S.-Canadian Acid Rain Envoys recommended a 5-year/$5 billion program to commercialize less expensive ways to control emissions which cause acid rain. Air pollution technology, such as scrubbers, has been available for emissions control, the Envoys recommended embarking on a program to reduce the cost of acid rain control legislation, while also achieving substantial emissions reduction.

Acceptance of the Envoys report by the President provided the Department of Energy with an opportunity to become a catalyst in the acid rain debate. Cheaper alternatives to scrubbers could retain the marketability of high sulfur coal, while reducing air pollution emissions.

Information provided at the hearing we held on March 4th made clear that scrubber costs are declining, and new and effective clean air technologies are being operated on a commercial scale. However, there is substantial indication that DOE's implementation of the Envoys' recommendation has had no impact on either scrubber costs or technology development.

DOE has claimed that the clean coal program, which was in place before release of the Envoys report in many respects satisfies the Envoys' recommendation. In contrast, the Congressional Research Service concluded that DOE projects properly attributed to the Envoys report constitute roughly 1 percent of the $5 billion commitment made in that report.

In the absence of DOE support, companies like Northern States Power have invested in a fluidized bed combustion facility and a spray dryer on their own. One witness last week testified that DOE's interference with projects made Federal funding undesirable. In short, there has been testimony that DOE is acting as a barrier, rather than a catalyst, in the development of more effective acid rain control technology.

The purpose of this hearing is to hear from DOE and the Environmental Protection Agency on their implementation of the program, as well as to receive comments from a critic of the agencies.

The panel today consists of J. Allen Wampler, Assistant Secretary for Fossil Energy, Department of Energy; Mary L. Walker, Assistant Secretary for Environment, Safety and Health, Department of Energy; J. Craig Potter, Assistant Administrator for Air, Noise and Radiation, U.S. Environmental Protection Agency.

Mr. Potter, you are accompanied by Mr. Frank Princiotta.

Mr. POTTER. Yes.

Senator MITCHELL. Is Mr. Princiotta here.

Mr. POTTER. Yes.

Senator MITCHELL. He is just arriving.

The other witness is David G. Hawkins, Senior Attorney with the National Resources Defense Council. I am going to ask Mr. Hawkins to come to the table. One of the problems in these hearings is that one group comes in, tells their story, and then leaves the room. Then someone else comes in and tells a completely different story, and there is no chance for an exchange of views.

Mr. Hawkins, if you wouldn't mind, I would like you to come up, and at the same time that the other witnesses speak, I want you to speak, and then we can get an exchange of views, where we are more likely to be informed, I think, as Members of the committee.

While you are all coming up to the table I will take this opportunity to acknowledge a statement from Senator Moynihan which will be made a part of the record at this point.

[The statement referred to follows:]

STATEMENT OF HON. DANIEL PATRICK MOYNIHAN, U.S. SENATOR FROM THE STATE OF NEW YORK

Mr. Chairman, I look forward to our hearing today. We are all eager to hear the Department of Energy and the Environmental Protection Agency describe the Clean Coal Technology Program, and how it relates to the recommendations of the Special Envoys' Report on Acid Rain—a report, I might add, that has been endorsed in full by the President. Something not many thought he would do.

The money spent on Clean Coal research by DOE and by EPA is well spent—that is not in doubt. Indeed anything that leads to cleaner and more efficient generation of electricity is most welcome. We must have a realistic idea of the options in order to make intelligent choices, and that is our job—to make those choices. Research is a clear necessity in that regard.

Indeed, I was author of the Acid Precipitation Act of 1979, the only acid rain legislation we've got. It set up the long term research program that has told us much of what we really know on the subject. But research is of little good if no money is spent to implement new technologies. Worse still if it becomes an excuse for not moving ahead when our best information tells us we should so do.

Last year President Reagan chose to fully endorse the recommendations of the Joint Report of the Special Envoys on Acid Rain, recommendations made by his designee, Mr. Drew Lewis, along with William Davis, Prime Minister Mulroney's representative. This is a promise Mr. Reagan made to Mr. Mulroney on behalf of the United States. Such things matter; governments rise and fall on account of them. They must be honored.

What I hope to learn from this morning's hearing is very simple—are we or are we not honoring that committment? Whether the Clean Coal Program is a worthy one is not at issue—what is at issue is whether the program actually fulfills the four criteria outlined in the Envoys' Report, which calls for $2.5 billion of government spending to improve acid rain control technologies. The Clean Coal Program now amounts to only $750 million; I share the widely held doubts that the money so far spent meets our obligation.

Senator **Mitchell**. Why don't we begin in the order that the witnesses have been listed. Because we do want to qet an exchange, I want to remind all of the witnesses of, the committee practice. All written statements will be placed in the record in full. I ask that you highlight your testimony in five minutes, make the main points that you want to make. You can be sure that you will have plenty of opportunity during the question and answer period to emphasize any point that you want. Otherwise, with four witnesses testifying, it would be quite a while before we got through the opening statements, leaving little time for comments.

I thank you all for coming. I look forward to hearing your testimony.

We will begin with you, Mr. Wampler. Welcome.

STATEMENT OF HON. J. ALLEN WAMPLER, ASSISTANT SECRETARY FOR FOSSIL ENERGY, ACCOMPANIED BY DONALD BAUER, PRINCIPAL DEPUTY ASSISTANT SECRETARY; AND JACK SIEGEL, DEPUTY ASSISTANT SECRETARY FOR COAL TECHNOLOGY

Mr. **Wampler**. Mr. Chairman and Members of the subcommittee:

I am pleased to join Assistant Secretary Walker in appearing before this Subcommittee and in presenting the Department of Energy's views on clean coal technology.

I have seated with me Mr. Donald Bauer, my Principal Deputy, and Mr. Jack Siegel, the Deputy Assistant Secretary for Coal Technology. Mr. Bauer has overseen the current DOE Clean Coal Technology Program since its creation in December of 1985.

I would ask, Mr. Chairman, that my written statement be placed in the record, and I will take only a few minutes to summarize some of its key points.

My testimony makes three fundamental points, Mr. Chairman:

First, that today's conventional control options for coal-fired power plants are limited and inherently costly. That point has been reinforced by many of the industrial witnesses that have appeared before this Committee, and it was also a point implicit in the Special Envoys' Report on Acid Rain last year.

In fact, the task before this Nation can be expressed no better than the following statement contained in the Special Envoys' Report:

> If the menu of control options were expanded, and if the new options were significantly cheaper, yet highly efficient, it would be easier to formulate an acid rain control plan that would have broader public appeal.

This is the goal of our Clean Coal Technology Program, Mr. Chairman, and that leads to the second point contained within my formal testimony.

The menu of options will, between now and the early 1990s, expand significantly not only for new grassroots plants but, perhaps more importantly, for existing facilities.

The emerging slate of advanced technologies includes techniques that extract sulfur and mineral matter either before, during or after the combustion process. Many combine effective sulfur dioxide control with the capability of controlling nitrogen oxide emissions—something today's installed population of flue gas scrubbers was never designed to do.

Some of the emerging coal technologies depart radically from the conventional concept of coal combustion. Instead, they convert coal initially into a combustible gas that can then power a combined-cycle turbine configuration.

The concepts may be varied, Mr. Chairman, but they are linked by a common characteristic—the capability to combine a consistently high degree of environmental effectiveness, economic viability, and plant reliability. They are relatively insensitive to coal type, and this could have a major positive effect on the stability of the workforce in the Nation's coalfields.

I have described in my testimony how we see these emerging concepts making their way into the marketplace, as a basis for new powerplants or as retrofits that can reduce emissions from existing plants, or as repowering options that can combine improved environmental performance with increased power output and plant life extension.

We believe the inherent advantages offered by many of these new technologies will lead to their commercial deployment through normal market forces and, in turn, that will continue the significant progress made in the last decade to improve the quality of the Nation's air.

We believe the benefits offered by several of these technologies, particularly in terms of increased power output, will, in fact, hasten the phasing out of older pre-NSPS powerplants, making them early candidates for repowering with fluidized bed combustion or gasification-combined cycle. And that, too, will result in positive benefits not only for the quality of our environment but for the continuing ability of our power generating sectors to function efficiently and reliably without imposing major economic burdens on consumers.

The third and final point of my statement, Mr. Chairman, is perhaps the most positive. It is simply that the Nation's Clean Coal Technology Program is truly a national program, not just a Federal activity.

Too often, I believe, the Nation's investment in Clean Coal Technology has been measured by the funding levels of the Federal Government. Clearly, the Federal Government has a role, and we are attempting to balance both the need to accelerate commercial-scale clean coal development with the equally pressing need to reduce the economic pressures exerted by the Federal deficit.

But often overlooked in analyzing the clean coal efforts in this country are the sizable commitments being made independently by the private sector and by State governments.

To provide a better perspective on the national commitment, we recently produced a report entitled "America's Clean Coal Commitment." Copies of that report have been provided to this subcommittee.

The report identifies an estimated $6.1 billion in funding planned both in the public and private sectors for new clean coal technology between 1986 and 1992. Mr. Chairman, I believe our calculations are conservative. The figure is likely to be much larger.

In short, Mr. Chairman, we have a unique opportunity today to remove this Nation from the dilemma of choosing between a better environment or the increased use of our most abundant and secure energy resource. We have the opportunity to resolve the conflicts between improved environmental quality and potential economic dislocation and hardship. We have the opportunity to develop an attractive slate of new technologies that can open up new trading markets for U.S.-coal overseas.

The Clean Coal Technology Program we have started, coupled with the additional competitive solicitations we have proposed and the efforts underway in the private sector, have placed us well down the path toward achieving those goals.

We would be pleased to discuss the specifics of these programs in more detail if Members of the subcommittee have questions.

Thank you, Mr. Chairman.

Senator MITCHELL. Thank you, Mr. Wampler.

Before proceeding to Ms. Walker's testimony, I note the presence of two other members of the subcommittee.

Senator Pressler, do you have any opening statement to make?

OPENING STATEMENT OF HON. LARRY PRESSLER, U.S. SENATOR FROM THE STATE OF SOUTH DAKOTA

Senator PRESSLER. Thank you, Mr. Chairman.

Let me say that I want to commend you for scheduling these hearings on clean coal technology and the U.S.-Canada Joint Report of of the Special Envoys on Acid Rain. This hearing recognizes the international impact of acid rain issues.

As Chairman of the Senate Foreign Relations Subcommittee on Arms Control, Oceans, International Operations and Environment, I chaired a hearing in 1982 on acid rain, and I believe the chairman was a witness at that hearing. The hearing focused on the status of bilateral negotiations between the United States and Canada. Several members of this committee participated in those hearings.

Since that time, the acid rain issue has not been resolved and it continues to strain relations between the United States and Canada. The U.S. and Canada have a long history of friendly and mutually beneficial relations, and it is essential to both nations that we continue that friendly relationship.

Over a year ago, the Joint Report of the Special Envoys on Acid Rain was presented to the President. That report included several recommendations including a major effort by the United States to implement emission control technologies. One of these new technologies is clean coal technology.

The Administration has implemented several clean coal technology projects. I am looking forward to hearing about our efforts and results in this area, and asking questions as to how progress is being made.

Thank you, Mr. Chairman.

Senator MITCHELL. Thank you, Senator Pressler.

The distinguished former chairman of our committee, Senator Stafford.

Senator STAFFORD. Thank you, Mr. Chairman.

I have no opening statement. I am here to listen and, I hope, learn.

Senator MITCHELL. Thank you, Mr. Chairman.

Ms. Walker, we are all here to listen and learn. Welcome, and we look forward to hearing from you.

STATEMENT OF HON. MARY L. WALKER, ASSISTANT SECRETARY FOR ENVIRONMENT, SAFETY, AND HEALTH, DEPARTMENT OF ENERGY, ACCOMPANIED BY TED WILLIAMS, DIRECTOR OF THE OFFICE OF ENVIRONMENTAL ANALYSIS

Ms. WALKER. Thank you, Mr. Chairman.

I am accompanied today by Ted Williams, sitting on my left, the Director of the Office of Environmental Analysis.

Senator MITCHELL. What is his name?

Ms. WALKER. Ted Williams, but he does not play baseball.

Senator MITCHELL. Where I grew up in New England, Mr. Williams, your namesake was a hero of all of our generations.

Ms. WALKER. He has the accent, but he doesn't have the swing.

Senator MITCHELL. We are honored by your name, if nothing else.

Ms. WALKER. My testimony today will give you, I think, a status report on where we are with the Envoys' Report, and it will draw from that Report findings and recommendations, and provide you with a report as to where we are.

Mr. Wampler has addressed the status of the specific clean coal technology activities. I would like to begin with the findings that the Envoys made. They made three basic findings:

First, acid rain is a serious environmental problem in both the U.S. and Canada, with the potential for high socio-economic costs.

Second, they found that acid rain is a serious transboundary problem, with diplomatic dimensions.

Third, at the present time, they found there are only a limited number of options that are available for major emissions reductions, all having high socio-economic costs.

The Envoys' recommendations were based on these findings and the wide differences that they noted between the U.S. and the Canadian perspectives. Their mandate was not to find a final solution. They recognized that the recommendations must be realistic, and they did not ask for immediate changes in the policies of the two nations.

Their recommendations were designed to reopen the dialogue, to begin steps to resolve our differences, and initiate preparations to increase the effectiveness of any future actions. Their recommendations were made in three areas:

Cooperative activities, which include reviewing existing regulatory programs for ways to address transboundary concerns, and establishing the Bilateral Advisory and Consultative Group, on which Mr. Wampler and I sit as members.

They also recommended an innovative control technology program, and this is, of course, the five year $5 billion commercial demonstration program, designed to expand the menu of control options available.

Lastly, they recommended certain things in the area of scientific research and research coordination between the two countries.

To give you an update of where we are, I can tell you that the fruitful dialogue that they wanted to see occur is well underway. As I indicated, the Bilateral Group has been established. It has met three times, the latest of these on February 25 in Ottawa, and we are now preparing a report on our first year's activities, a joint report.

We have been discussing the acid rain issue periodically at the cabinet level, most recently between Secretary of State Shultz and his Canadian counterpart, Joe Clark. Discussions have also been had between DOE and Canadian officials on the specifics of the clean coal program, and this included a December meeting between Secretary Herrington and the Canadian Environment Minister McMillan.

We expect that specific detailed technology discussions will occur later this month, or in April, between the staff of the Department of Energy and the Canadian Department of Energy, Mines, and Resources.

The notification process for changes in the relevant regulations and laws in place since 1982 have been judged to meet that particular recommendation of the Envoys.

Lastly, as a result of Vice President Bush's meeting on January 21 with Prime Minister Mulroney, the Vice President asked for a fresh look to be taken at our progress in meeting the Envoys' recommendations. This fresh look is underway, and its results are expected to be a part of the Summit discussions between the President and Prime Minister Mulroney in early April.

Assistant Secretary Wampler has described the technology and the detail of the National Clean Coal Program. Our implementing actions over the past year to support the recommendations of the Envoys have been focused on identifying and advancing efforts in this area. Recognized by the President as supportive of the Envoys' recommendations, he fully endorsed that report.

This program of sequential solicitation of private proposals and review of areas needing more coverage will allow intelligent evaluation of the results of each set of projects and the need for added efforts.

Effective and increased collaboration in the U.S. and Canada on scientific research is also underway. As I indicated, the Bilateral Group is preparing a report, and the scientific report is expected to be released later this month.

In concluding, then, I believe that the implementation of the Envoys' recommendations that we have been undertaking has established a meaningful process that is working. The results of the Clean Coal Technology Program should be responsive to the time. Research results are sufficient to define what, if any, further steps will be necessary.

The Administration is committed to controlling acid rain, once we know that action will achieve the intended results, and those results will justify the costs. Our current scientific understanding tells us that we have the time to follow through on this worthy process, and until that time, the Clean Coal Program serves the United States energy and environmental goals, providing new and improved control options that are more environmentally sound than existing ones, that will be considered in all our existing environmental management programs.

Thank you.

Senator MITCHELL. Thank you very much, Ms. Walker.

Mr. Potter, welcome again. We look forward to hearing from you as always.

STATEMENT OF J. CRAIG POTTER, ASSISTANT ADMINISTRATOR FOR AIR AND RADIATION, ENVIRONMENTAL PROTECTION AGENCY, ACCOMPANIED BY FRANK PRINCIOTTA, DIRECTOR, AIR AND ENERGY ENGINEERING RESEARCH LABORATORY OFFICE OF RESEARCH AND DEVELOPMENT, EPA RESEARCH TRIANGLE PARK

Mr. POTTER. Thank you, Mr. Chairman. It is a pleasure to be here.

I have with me Frank Princiotta, who is the head of the Engineering Lab in North Carolina, to deal with technical matters should they come up, Mr. Chairman.

I am pleased to be here to discuss EPA's role in the development of clean coal technologies. There are just a few points that I would like to make in summarizing my statement, if I might.

It seems to me at the outset that there are two basic reasons that we should all be concerned about the future of these technologies. From an air pollution point of view, herein may well lie a key, if not the key, to future substantial emission reductions. Cost effectiveness and other issues in particular may provide special incentives to look at and use these technologies in the future.

The second point is, of course, that herein will certainly lie a key to our future energy independence, for it would allow us to continue to rely and possibly even expand our reliance on our vast coal deposits.

As with all technically complex solutions, there are problems, of course. The difficulties of retrofit, for example, can be enormous. Applications are site specific, and they are highly variable. We have had great experience in seeing some of these difficulties.

The technologies themselves while relatively simple, conceptually, are chemically, physically, and technically quite complex. For example, the location of the injection systems above the firing zone in the boilers is a technically complicated matter.

The particle size, the moisture content of injected materials, the need to test various solvents, and the need to control temperature ranges, and so forth, are important factors in dealing with development and demonstration of these technologies. Nevertheless, it seems clear to me that we have real need to jointly pursue these technologies, with the support of Congress, especially this committee.

My statement, Mr. Chairman, discusses our work at EPA with these technologies. Primarily, I focus on LIMB. I am not going to go into great detail about those technologies, except to say that our approach has generally been the development and demonstration of SO_2 and NO_X control technologies.

Not only have we looked at LIMB, we are in the process of expanding the effort with regard to LIMB. We have also looked at other technologies such as, for example, sorbent injection, E-SO_X applications, NO_X-reburning, and in many cases this work is done in combination with other people, both in the government and in the private sector.

As I discuss in my statement, there are three basic approaches that might be elements of any SO_2/NO_X control or reduction strategy beyond NSPS. The relative role of the technologies would very much depend, and I stress this, would very much depend on the level and timing of the need for reductions in emissions.

The approaches that I have outlined in my statement include a straight retrofit approach of existing boilers; the repowering approach as, for example, with atmospheric fluidized bed combustion technologies, and finally, the use of advanced technology and state-of-the-art SO_2 and NO_X controls. An example here might be the integrated gasification combined cycle project.

In conclusion, Mr. Chairman, given congressional guidance in the Clean Air Act and in the Clean Coal Technology authorization and appropriations received so far, we are continuing to make progress in reducing SO_2 and NO_X emissions. Based on what we know at the present time, I can't say that I disagree with that direction, in fact, I support it.

Finally, with respect to clean coal technology, while we might argue about this or that technology, we strongly support the approach. The reason, of course, is because the technologies that are being developed, or something very much like them, may well hold the key to major cost effective SO_2 and NO_X emission reductions in the future.

Thank you very much.

Senator MITCHELL. Thank you, Mr. Potter.

Mr. Hawkins, welcome. We look forward, as always, to hearing from you.

STATEMENT OF DAVID G. HAWKINS, SENIOR ATTORNEY NATURAL RESOURCES DEFENSE COUNCIL

Mr. HAWKINS. Thank you, Mr. Chairman. I do appreciate the opportunity to be here and speak on behalf of the Natural Resource Defense Council and the National Clean Air Coalition.

I would like to state the Coalition's views at the outset of my remarks, which is that over two decades of research have produced a set of fully demonstrated methods that can control precursors emissions to acid rain. These available control methods are adequate to achieve, in a reliable and affordable fashion, any level of emission reductions proposed in this or the last several Congresses.

There are additional clean coal demonstration projects now underway, and they may prove out several additional useful methods that can complement the current mix of controls, but this demonstration program is not, as claimed by acid rain control opponents, a reason to delay enactment of a law requiring emission reductions on a prompt schedule.

Since 1980, we have all been the audience for arguments by opponents of acid rain control. It has been the familiar series of arguments. First, there is no problem. Then, we don't understand the cause of the problem. Then, somebody else causes the problem. Then, we don't know how to fix the problem, or we can't afford to do it.

As the weaknesses of these arguments have been exposed, control opponents have turned to what is traditionally the last weapon in their arsenal, delay. They predict a vastly superior solution to the problem just over the horizon, and ask us all to wait for it.

Let me state our views on these points.

First, current control methods can do the job. The argument that we have to wait for controls is not a new one. Essentially the same argument was made 20 years ago to the predecessor of this subcommittee by the very same industries that are now most vigorously opposing acid rain controls.

Witnesses, 20 years ago, pointed to the technology of flue gas sulfurization as a method, with perhaps three to five years of additional demonstration work, that could be used to attack the coal sulfur dioxide problem.

Flue gas systems and other methods were developed, they were improved through the 1970s, and they are now proven and reliable methods of controlling both new and existing plants. Now that we have them, though, they are not good enough.

We are now being pointed to a new set of emerging technologies. The principal advantage of these new technologies, for the purpose of the argument, is that they are not here yet.

Opponents of acid rain controls charge that today's technologies are too expensive. However, their assessments exaggerate the true cost of these technologies. By using high capital cost assumptions for flue gas systems, applying high capital charge rates and other misleading accounting techniques, and by assuming installation of far more flue gas capacity than would be required to achieve required reductions in various bills, analysts have been able to generate very high cost estimates, which I detail in my statement.

I would also like to call the subcommittee's attention to the acid rain control program now being implemented in West Germany. Under legislation enacted in 1983, every large coal-fired power plant in West Germany, that will continue to operate past 1993, is being required now to install and operate a high efficiency FGD system by the beginning of 1988 for sulfur dioxide and 1990 for nitrogen oxide.

Thus, less than nine months from today, West Germany will have fully implemented a wholesale FGD retrofit program, and this is in a country which began the acid rain debate, really, later than the United States did. The cost estimates from Germany show surprisingly lower costs than are being used in estimates of U.S. control programs.

The coalition neither advocates nor opposes a wholesale retrofit program of FGD, or any other technology specific solutions to acid rain, but it must be noted that West Germany, which like the

United States relies heavily on domestic coal and competes vigorously in international trade, is demonstrating that such a strategy is technically and economically feasible, and can be implemented more rapidly than the scheduled contained in any bills now pending in Congress.

With respect to the applicability of clean coal technology, the relevant question is how many can be used in a retrofit context. In my statement, I go through in detail and conclude that there appear to be several technologies that could be and the industry is prepared to implement for the retrofit market. But there is no conflict between implementing and demonstrating these technologies and adoption of a bill.

As the DOE proposals indicate, most of the results from these promising technologies will be in by 1991 which, for example, under the chairman's bill, S. 321, is adequate time in order to make a decision to commit to a particular technology, and I have described the process in my testimony.

Mr. Chairman, I will attempt to summarize the points that I do make in the portion of my testimony relating to the President's commitment to the Envoys Program. Let me say that I think the evidence indicates that that commitment has not been fulfilled.

We recommend that the President, in meeting with Prime Minister Mulroney in Canada, in April, reassess the situation, reassess the Administration's position, and once and for all agree that it is appropriate for the Congress to move forward and adopt acid rain control legislation.

Regardless of whether the Administration takes that position, however, we urge the Congress to do so.

Thank you very much.

Senator MITCHELL. Thank you, Mr. Hawkins.

I am pleased to note the presence of Senator Graham.

Senator Graham, do you have an opening statement that you wish to make?

Senator GRAHAM. No, Mr. Chairman.

Senator MITCHELL. I will begin the first round of questioning. Under committee procedures, we will go in the order in which Senators appeared, Senator Pressler, Senator Stafford, Senator Graham following myself. We will limit the first round of questioning to five minutes, and we will continue for as long as there are questions to be asked.

Mr. Wampler, I want to begin with a comment, and then I will proceed to a question. On page 3 of your prepared statement, it reads:

> Continued application of flue gas scrubbers on new power plants could keep nationwide SO_2 emissions from rising abruptly, but will not reduce overall emissions until existing pre-new source performance standard emitters are retired.

That statement is supported by a graph on page 26 of the Department of Energy's Report to Congress on the relationship between projects selected for the Clean Coal Technology program and the recommendations of the Special Envoys on Acid Rain. That graph shows no discernible decline in SO_2 emissions through the year 2030 under the existing Clean Air Act, assuming a 60-year plant life.

As you know, utilities are extending the useful life of plants in order to limit capital expenditures. EPA now assumes a 60-year useful life in its analyses. This extension process does not always result in emission reductions to installation of flue gas control devices as your graph demonstrates.

My comment, first, is that the failure to achieve significant reductions in sulfur dioxide emissions is precisely the problem that the majority of the members of this committee are committed to deal with. Most of us support a significant reduction in sulfur dioxide emissions over the next ten years. We do not propose to wait for 50 or 60 years.

On page 7 of your testimony, you state that the longer term strategy for SO_2 controls, that of replacement of retiring plants, has several advantages over requirements which would result in the immediate installation of SO_2 controls that exist in plants. You cite as advantages reduction in present value utility costs, prevention of adverse effects on coal production, and the ability to defray control costs. Of course, what you omit entirely is the cost of such delay.

By DOE's own admission, the strategy of replacement of retiring plants will not result in SO_2 emissions reductions for another 40 years. During that time, the cost of further environmental damage, damage to human health, damage to other materials may far exceed the cost to the utilities of reducing their emissions.

So I repeat, it is my position, and I believe the position of the majority of the members of this committee, including the former chairman, that significant SO_2 reductions must be achieved in the near term, not 40 years from now. A policy that seeks only to reduce the financial cost to the utilities, and ignores the cost to human health and environmental damage, is unacceptable.

It is my understanding that DOE has refused to release environmental assessments for the projects selected in Phase I of the Clean Coal program. This means that there is no available independent assessment of these technologies' ability to reduce sulfur dioxide and nitrogen oxide emissions. At the same time, DOE has submitted the projects to Congress for a 30-day review period.

How can Congress make a decision if the essential data on emissions reduction or other environmental considerations are not available?

Mr. WAMPLER. Let me preface my answer with a quick recap of the purpose behind the programmatic environmental assessment. As you are aware, and as you stated, the Clean Coal Technology program has been on a very fast track, and it was placed on a very fast track by the congressional legislation that mandated it.

Normally, NEPA requires an overall environmental assessment to be made prior to the beginning of a program, followed by project specific assessments, but in this case the congressional time-table didn't allow for a programmatic assessment to be done prior to initiation of the Program. Therefore, in order to comply with the intent of NEPA, we developed a programmatic assessment based on the data that we received from the individual submitters.

It analyzed the potential environmental impact of all the candidate projects within the competitive range, and I think that was 39.

The assessment was then forwarded to the NEPA section within Assistant Secretary Walker's office for independent review.

The unique character of the assessment required that it contain a considerable amount of company-supplied proprietary data or business confidential data. For example, their market projections, business plans, et cetera. Not only was data included from the nine projects subsequently selected, but also from those that were not selected.

It is the proprietary and business confidential data from both the companies that were selected and the companies that were not selected, that prevents us from publicly releasing this assessment and information.

Mr. **Bauer**. Mr. Chairman, all the data on the nine selected projects, for which we are undergoing negotiations, the cooperative agreement, the report to the Hill, the NEPA documentation, all of that; what we are saying to the subcommittee, to the world, to the public, is that we are still in the process of negotiating on all of these activities, and there could be a possibility that we would be unable to reach closure on the nine, which would require that we go back, deselect and reselect.

We will, though, however, respond to any specific request from the Congress. If they want any specific report or document, signed by the subcommittee chairman, asking for a particular document. We will provide that document to the Congress for whatever they want to do with it, their study, their analysis, or whatever, Mr. Chairman.

Senator **Mitchell**. If we request the data on emission reductions and environmental assessment, you will provide them to us?

Mr. **Wampler**. Mr. Chairman, if you write, as subcommittee chairman or committee chairman, and say, I want the following data, the data will be provided with the appropriate caveat which says, the data that we used in our analysis—which is part of an ongoing process—includes business confidential data, and then we will put in the caveats and provide the data.

Senator **Mitchell**. Will that include emissions data?

Mr. **Wampler**. Whatever data, Mr. Chairman.

Senator **Mitchell**. I hereby request it, and you will get a letter on that very shortly.

Mr. **Wampler**. With the specifics of what you want.

Senator **Mitchell**. Yes.

Senator **Pressler**. Thank you, Mr. Chairman.

Let me address the question to any volunteer. In layman's terms, what is the process used in Clean Coal Technology projects?

How difficult is it to implement these technologies on current plants?

In other words, would you describe in detail the process used in Clean Coal Technology?

Mr. **Wampler**. Let me ask Jack Siegel, who is the Deputy Assistant Secretary for Coal Technologies, if he would answer the question, with your permission, Mr. Chairman.

Mr. **Siegel**. I am Jack Siegel, Deputy Assistant Secretary for Coal Technologies at the Department of Energy.

It is a very complex question you asked, Senator. There are a wide variety of technologies for a wide variety of applications that are being developed and considered as clean coal technologies. They include processes such as coal cleaning, where you take the coal out of the mine, grind it up very finely, and remove the sulfur and ash particles, and that clean coal can then be used in an existing powerplant. That existing powerplant might have to undergo some modification, especially to the particulate matter control equipment. That is a fairly inexpensive way of cleaning coal to moderate levels.

Senator **Pressler**. What actually happens to the coal?

Mr. **Siegel**. Not much happens to the coal. It is ground up into very, very fine particles, and then the sulfur particles, the pyritic sulfur—there are two types of sulfur in the coal, organic and pyritic—the pyritic sulfur, which represents up to 70 or 80 percent of the sulfur in some coals, is removed through normal, conventional techniques.

The clean coal technologies also include a lot of other processes that are used to modify the combustion process, such as fluidized bed combustion, which is basically a new technology that allows coal to be burned very efficiently, very economically, and by adding some sorbent to remove the SO_2, control the SO_2 to very high levels.

We have both pressurized and atmospheric fluidized bed combustion. To use that technology on an existing power plant, you would have to make major modifications to the plant. The costs are high, but in addition to pollution control, you also get additional power output, and you extend the life of the plant. So we think that for a large number of utility systems that need additional power and that need to extend the life of their plant, fluidized bed combustion might be a good option.

I could go on. There is quite a variety of technologies. In fact, in our report, "America's Clean Coal Commitment," which we have, as Mr. Wampler said, provided copies to the staff, we go into some detail on each of those technologies, how they work, what their attributes are, and what the estimated economic costs are, and so forth.

Senator **Pressler**. What would be a possible time-table for fully implementing clean coal technology to provide an effective means of reducing the sulfur dioxide emissions?

Mr. **Wampler**. Senator, the time frames vary considerably for different technologies. Let me give you an example of several. For the LIMB program that EPA is manging, we would consider that sufficient data from the past and currently ongoing studies would make this technology available—that is the data would be available—in the next one to two years.

Other projects that would require more construction would, obviously, take longer. Repowering options, which look very attractive, and which include the gas-fired combined cycle and pressurized fluidized bed combustion, about which Mr. Siegel was just testifying, would be available in the time frame of 1992 to 1993.

What our goal is, in the Department, is to have all data available to the industry in time to be effective in the planning process, the window that we see is in the mid-1990s. At that time, the utility industry will be making, in our opinion, some very important decisions based entirely on the age of their existing boiler population at that point in time. We are aiming for that window in the mid-1990s.

Senator Pressler. Thank you very much.

Senator Mitchell. Thank you, Senator Pressler.

Senator Stafford.

Senator Stafford. Thank you, Mr. Chairman.

First of all, I want to direct a request to the Department of Energy and the Environmental Protection Agency representatives who are here this morning, and that is if the Department of Energy and the Environmental Protection Agency have either conducted internal reviews or commissioned outside analyses of various acid rain control options?

The committee has informally received some of these, but I believe there are others. My request is, would both DOE and EPA please provide the committee with copies of all analyses which have been conducted, especially those done by the consulting firm ICS. I am sure that you understand that these would be quite helpful to us in designing a cost effective pollution control program.

[The information requested follows:]

In response to the request by Senator Stafford for copies of all Department of Energy analyses of acid rain control proposals, the following are provided:

"An Analysis of Proposed Legislation to Control Acid Rain," ANL/EES-TM-209, January 1983.

"Proposals for Acid-Rain Control from the 98th Congress," ANL/EES-TM-281, October 1984.

"Controlling Acidic Deposition: Targeted Strategies for Reducing Sulfur Dioxide Emissions", ANL/ESS-TM-282, October 1984.

"The Control-or-Retire Streategy for Reducing Sulfur Dioxide Emissions from Powerplants," ANL/EES-TM-283, October 1984.

"And Eonomic Assessment of Long-Term Emission Reduction Alternatives," ICF Incorporated, may 1985.

All analyses were performed for the Department of Energy; the first four by the Argonne National Laboratory and the last by ICF Incorporated. Analytic assumptions are clearly defined within each report.

Senator Stafford. In addition to the ICS analyses, there is a variety of other information which would be helpful. I will supply you with a list of that information after the hearing. But for EPA, I would like to make a specific request that we be provided with the rural ozone models which the agency has developed. If possible, that should be in a computer format which the committee might use.

May I ask the witnesses from EPA and Energy, Mr. Wampler and Mr. Potter, have you seen a report issued some little time ago indicating that should we make an immediate effort to substantially reduce sulfur dioxide and nitrogen oxide emissions in this country, there would be a considerable financial benefit, according to that report, in parts of the country, including the State of Michigan.

It would be something like $11 or $13 billion worth of business generated in this country in supplying the materiel to reduce the emissions that cause acid rain. Are you familiar with that, Mr. Potter?

Mr. Potter. Mr. Stafford, I am not familiar with that report.

Senator Stafford. Have you seen it, Mr. Wampler, or anybody else?

Mr. **Wampler**. I am not familiar with it, except for having heard of it.

Senator **Stafford**. It got quite a lot of attention in the New York Times, which is my source of information for that. I would appreciate it if you could find it, and if you might have some comments on it in writing, it would be helpful to us.

Mr. Wampler, in May of 1985, the consulting firm ICS conducted an analysis for the Department of Energy entitled "An Economic Assessment of Long Term Emission Reductions Alternatives." That assessment assumed that the powerplants in the United States would have an effective life of 60 years. If this assumption is correct, according to the assessment, it would be the year 2030, nearly half a century from now, before air pollution can decline substantially.

Why did the Department assume a 60-year life time? Considering the fact that the Tennessee Valley Authority has told the committee that it now plans to never retire its plants, are we even safe in assuming a 60-year life cycle for existing plants?

Mr. **Wampler**. Senator, with your permission, let me defer to Mary Walker.

Ms. **Walker**. The report you are referring to assumed a range of 45 to 60-year life. It is my understanding that this was done on a basis so that we could understand what the worst case analysis would be, because that is the potential.

Senator **Stafford**. In order for powerplants to extend their useful life to 60 years, it seems logical that they would be required to undertake interim upgrades. Indeed, it looks like about two-thirds of the submittals received by DOE, the Department of Energy, for the Clean Coal Technology program are for retrofit, repowering, or modernizing existing plants. The ICS analysis, we believe, states that for a powerplant to exist 60 years, it must undergo a life extending refurbishment at about 30 years of age.

So my question to either Mr. Wampler, or you, Mr. Potter, would be: Is 30 years about the right point for a plant to be replaced or to undergo a retrofit?

Mr. **Potter**. I think, Mr. Chairman, as far as the actual time frame, I would probably defer to the technology experts.

I would say this, however, the apparent time lag in NSPS coming into effect is something that we are concerned about. I think, in the absence of further action by Congress, further clarification, I think it underscores the importance of CCT effort as an additional gain on emission reductions.

Senator **Stafford**. Would either of the other witnesses want to add anything to that?

Ms. **Walker**. If I still remember the question, I think the answer is yes.

Mr. **Wampler**. Senator Stafford, I am told that the 30 to 60-year time frame is probably an accurate time frame.

Senator **Stafford**. In that case, my last question on this cycle would be, just to note, Mr. Potter, that you indicated three items of current technology which are available for retrofit purposes at the present time that would have a pronounced effect on reducing sulfur and NO_x emissions, and that appears on page 2 of your statement, I think.

Mr. **POTTER**. Yes.

Senator **STAFFORD**. We will have a second round.

Senator **MITCHELL**. Yes, Senator Stafford.

We are pleased to have been joined by Senator Lautenberg.

Senator, do you have an opening statement?

Senator **LAUTENBERG**. I have no opening statement, Mr. Chairman. What I would like to do, Mr. Chairman, is to see that the record is open so that I can submit some questions to the witnesses. I have a conflict with another hearing.

Senator **MITCHELL**. That will be done, Senator.

Senator **LAUTENBERG**. Thank you, Mr. Chairman.

We are also pleased that the former chairman of this subcommittee, who has done so much to preserve and protect the American environment, Senator Chafee, is here.

Senator Chafee, do you have an opening statement.

Senator **CHAFEE**. No, I don't, Mr. Chairman. Thank you very much.

I apologize for being here intermittently; the Finance Committee is also having a major hearing this morning, and indeed might be marking up something. I appreciate the opportunity to certainly look at the record.

Senator **MITCHELL**. Thank you, Senator.

Senator Graham, do you have questions?

Senator **GRAHAM**. Thank you, Mr. Chairman.

I would like to ask this question.

Secretary Wampler, the limestone injection multi-stage burner technology, or LIMB, achieved a significant removal of SO_2, especially when combined with coal washing. I notice that there is currently a LIMB project among the nine DOE Clean Coal projects.

Do you anticipate that a LIMB project will be among the group funded in Phase II or Phase III of the Clean Coal program?

Mr. **WAMPLER**. We have had some LIMB projects proposed in the informational solicitation of statements of interest. It is premature at this point in time to make any decision on that, but some have been proposed, yes.

Senator **GRAHAM**. In terms of selecting projects for consideration under Phase II and Phase III, what priority is being given to those that might have the most immediate impact because of the current state of knowledge of those technologies?

Mr. **WAMPLER**. What we are doing in Round II and Round III that is different from what was done in Round I, is that Round II and III both focus on demonstrating technologies for retrofit, repowering, and modernizing, which is different from the broader focus of Round I; these would more closely track the recommendations in the Envoys' Report. Round III was set up specifically to take into account technologies that were not mature enough in Round I and Round II.

As far as the focus, at this point in time, other than criteria, we don't want to limit the kinds of projects that are submitted to the Department for evaluation. It serves two purposes. I think it gives us a maximum number of different projects to consider, and it tends not to restrict the private sector on what it proposes to the Department. We don't want to preclude anything from being proposed at this point in time.

Senator GRAHAM. If there is a priority on expedition, would it not be desirable to give some special attention to those technologies which have, on a smaller scale, demonstrated the promise of commercial scale application to immediately impact the problem?

Mr. WAMPLER. We are certainly looking at that at this point. We are also in the process of developing criteria for Rounds II and III, and we will certainly factor that into our consideration.

Senator GRAHAM. Those criteria have not been determined as of now?

Mr. WAMPLER. No, they haven't been determined. We are in the process of determining the criteria now.

Senator GRAHAM. When will the RFPs or other requests for Round II be submitted?

Mr. WAMPLER. It wasn't an RFP, it was a request for statements of interest, and that was on November 12, 1986. The first report to Congress, the initial report, was made last Friday. We have an additional report to Congress that is due on May 12, which will be a more detailed report on the kinds of projects that were proposed in the statements of interest that were received under Round II.

Senator GRAHAM. At the time that proposals were submitted, there was not a predetermined indication to the applicants of the standards by which those projects would be evaluated, and the characteristics that would most likely lead to selection?

Mr. WAMPLER. We had some congressional guidance in connection with the 1987 appropriation. I will let Mr. Siegel explain that in more detail for you, with your permission.

Mr. SIEGEL. In our 1987 appropriation, Congress asked us to issue an informational solicitation asking for proposed information on projects involving the demonstration of retrofit, repowering, or modernization technologies for existing boilers.

In the informational solicitation, the intention was to see what interest in and what types of projects were out there for the retrofit and repowering of existing powerplants.

We received 139 proposals, and based partly on the response that we got to that invitation, the Administration decided to request appropriations starting in the 1988 budget, that would result in actual proposals being submitted. We are in the process now of determining what the criteria should be for that round of proposals.

Senator GRAHAM. Thank you, Mr. Chairman.

Senator MITCHELL. Thank you very much, Senator Graham.

We will now proceed to the next round of questioning.

Mr. Potter, the Joint Envoys' report says, and I quote:

> The U.S. Environmental Protection Agency, and the Department of Energy should provide the expertise necessary to select demonstration projects.

On page 9 of your testimony, you state, and I quote:

> EPA did not have a role in the final selection process, nor will it have any technical management role for the selected Clean Coal projects.

Based upon your words, it sounds to me like you are not doing your job as stated by the Envoys' report, and my question is, why not?

Mr. POTTER. We have had a good bit of discussion about our role with regard to the DOE's selection of projects, Mr. Chairman. Perhaps it might be appropriate to respond to specific limitations in terms of the way they do business. We have provided some technical assistance, particularly in the first round of CCT projects. We have not been involved, as my statement indicates, in the actual selection of projects.

Senator MITCHELL. I know, but why not?

Mr. POTTER. That is just not a role from a policy standpoint that we are taking at the present time.

Senator MITCHELL. The Envoys' report said that you would. The President of the United States endorsed this report.

Mr. POTTER. I understand. One of the problems that we have, Mr. Chairman, is that there is not a total overlap between the Envoys' report and the Clean Coal Technology demonstrations effort. The only vehicle that presently exists, beyond the request for this budget year for further activity, is the Clean Coal Technology Demonstration in terms of the implementation of the Envoys' report.

The action there, as a policy matter, is being headed by DOE. We have talked to that in the past, and we will continue to work with them. They certainly understand the concerns we have with regard to technologies and how they might be used, the desire on our part to focus on retrofit. I think that we have come a good long way in the recent past in discussing and working through that issue. I think that this committee has helped to make that happen.

Senator MITCHELL. I can't tell from your answer whether you are just saying in a nice way that they have frozen you out, and you want to have a larger role, or that you don't feel that it is appropriate to have a role.

Why don't you answer that. Do you feel that EPA should play a larger role than it has played in the program?

Mr. POTTER. Given the limitations in the Clean Coal Technology program, and in the absence of a further decision about exactly how we are going to implement the Envoys' report, I would say that we are going to have to be limited in the interaction we have with CCT.

Senator MITCHELL. I still can't tell what you are saying. I am going to go on to something else. I am going to submit some questions to you in writing on that point, and to you, too, Mr. Wampler.

Mr. Wampler, in your statement, on page 18, you said, and I quote, "All nine demonstration projects met at least two of the Lewis-Davis criteria." Lewis-Davis refers to the Envoys.

In the executive summary to the DOE report to Congress on the relationship between the Clean Coal Technology program and the Envoys' report, there was this statement, and I quote:

> Many of the technologies selected under the Clean Coal Technology program are consistent with technologies which would have been selected if one followed the recommendations in the Envoys' report.

The statement and the conclusion in the report suggest that satisfying any one of the four criteria set forth in the Envoys' report means that the technology selected meets the Envoys' requirement.

My reading of the Envoys' report is to the contrary, as is the reading of the Canadian Government. My reading is that all of the criteria listed by the Envoys must be satisfied in each project. The Canadian government has submitted a written statement for this hearing, and they concluded that only two of the nine selected projects even come close to meeting the Special Envoys' recommendations.

What is the basis for your conclusion that meeting any one of the four criteria is sufficient, as opposed to what I think is rather clear reading of the English language that all four must be met?

Mr. **Wampler**. I would have to say, Mr. Chairman, that it is a matter that is subject to interpretation. I remember the uses of the term "viable" in some of our discussions with the Canadians as appropriately described.

Mary Walker can expand on exactly what the Envoys' report does say and what we interpret that to mean.

Ms. **Walker**. Mr. Chairman, I think that it is clear that the Envoys did lay out criteria, but even in the laying out of those criteria, they did not lay them out as having all to be satisfied for each particular project. Our discussions with the Canadians, I think that would be supportive, because even in the way they would analyze our projects, they would give significant credit to them on the basis that many of them satisfy the criteria in part. Even they would interpret it along with us, I believe.

Senator **Mitchell**. Wait a minute, are you saying that the Canadians agree with you that you don't have to meet all four of the criteria?

Ms. **Walker**. I am saying that the Canadians would give credit to our projects perhaps on a different basis than we would, but certainly to those projects that meet some of the criteria, even though they don't meet all.

Senator **Mitchell**. I can't tell which way you are answering. I gather you are saying, that your interpretation of the Envoys' report is that a project need meet some but not all of the four criteria, and the Canadians agree with you?

Ms. **Walker**. Let me rephrase it just a little bit. I think we would like to have, obviously, our projects meet as many of or all of the criteria, if possible. What we have attempted to do, in a fair review of the projects arising from the Clean Coal Technology Program per se, is to fairly assess which criteria are met by which project. What we have said is that all of them meet some of the criteria, although all of them do not meet all of the criteria. The Canadians have recognized with us, even in their own analysis, which may disagree somewhat with ours, as to how much credit be given. They have recognized the value of crediting toward the Envoys' Report implementation of those projects that do meet some of the criteria.

What I am saying is that I don't think either country would say, you can't even consider a project as implementing the report or in furtherance of the Report if it doesn't meet all of the criteria. It is not to say that this might not be a goal, but given where we were with the Program when the Envoys' Report was fully endorsed, obviously, we had a program on the shelf.

What we are saying now is that, yes, you should consider that some of the projects certainly move us toward implementing the Envoys' Report because, as I indicated, they all meet some of the criteria. I think when you look at the criteria in the Envoys' Report, you can see that some of the criteria are a reflection of what the Envoys referred to as "special considerations should be given to this," or "you should also consider." They are not saying, "The following four criteria must be met for each of these projects."

Again, it is subject to interpretation, but I think even in reviewing the projects that have thus far been approved for negotiation, we have attempted to fairly match the criteria with them, and say when they move us toward implementing the criteria and when perhaps they are not a complete match.

Senator MITCHELL. My time is up. I want to return to this because I don't agree with you, and I would like to pursue that a little further, but my time is up and I will wait for the next round. Senator Stafford.

Senator STAFFORD. Thank you, Mr. Chairman.

I must say that I haven't directed any questions to Mr. Hawkins, but I am impressed by what he said this morning, particularly when he pointed out that in Germany, which came into the debate on acid rain quite some time before the United States, nevertheless, they have taken steps, which, should we take them in this country, would greatly reduce our problems with acid rain. They have done that, apparently, in the belief that the benefits to be derived are great, and that they would not be at a competitive disadvantage with the United States, or the other industrialized nations.

Then recalling that this committee has already heard a panel of distinguished health experts, including Dr. Richard Narkowicz of Burlington, on the health hazards of acid rain quite recently, I must say that their testimony was very persuasive to those of us who believe that the time is long overdue to achieve further significant reductions in acid rain.

I don't think that we can wait forever for better technology because, as Mr. Potter has testified earlier, there is adequate technology available today. In the light of the testimony of the health experts, and the scientific evidence that sulfur emissions do threaten the health of young Americans, babies, as well as aquatic life, and probably crops and forests beyond that, I think that it is obvious that the time has come to take some really significant steps in reducing acid rain legislation with the available technology that we have today.

I have to ask the members of this panel if any of them can give me any good reason why we should not initiate further steps with the available technology for acid rain reduction that we have today, why we should not take those steps right now. I wonder if any member of the panel wishes to address that?

Mr. POTTER. I can respond to that, Senator. Under the existing Clean Air Act, we are attaining goals that have been set, as you know. We also have in that law the NSPS system which was intended over time to replace old, worn out technology. That is an issue that we are concerned about.

We are currently in the process, as the law tells us we should be, of reassessing a health standard for SO_2. We are very actively involved in that, and I think the committee is very well aware of that activity.

With regard to what I think you refer to, which is the acid aerosol problem, and the presence of sulfates in the atmosphere that may come from SO_2 emissions, it is an issue that we are concerned about. I would caution you, however, on the relationship in the science there because it is a very complicated interaction.

We are talking about something that is similar to the kinds of things that happen in the transformation of bulk organics into ozone in the atmosphere. The chemistry here, and the modeling are just not there yet. But this is a problem that we are concerned about, and we are going to be looking at it.

Senator **Stafford**. Any further comments?

Mr. **Wampler**. Senator, we see, and I think I can best describe it as a window. We see that the NAPAP report, that Assistant Secretary Walker can certainly expand on, is going to be finished in about three years. It is a ten-year report that has already had seven years of effort put into it.

We see a utility window opening with the aging power plants at about that same time frame. We see an emerging set of technologies that we think can be, from the initial cost estimates, extremely cost effective in terms of cost to the consumer of power, hitting about that same time.

It seems to us that given those factors and given the fact that we are seeing SO_2 reductions, it would be prudent to wait until all of those pieces of evidence are in.

Mr. **Hawkins**. Senator Stafford, I cannot agree that the Clean Air Act is doing its job.

In a report that was sent to this subcommittee last September, EPA submitted an analysis that showed that the utility powerplant emissions of sulfur dioxide would rise by nearly five million tons, from 17.4 million tons in 1980 to over 22 million tons in the year 2010.

Similar, a six million ton increase in nitrogen oxide emissions from those same sources is projected, a double, from somewhat over six million tons in 1980 to over 12 million tons in the Year 2010.

We are going in the wrong direction under the current law. We need new programs to reduce emissions to supplement the basic 1970 and 1977 law. We are not alone in advocating this. Twenty-two countries of the Atlantic Alliance have met over the last five years to discuss these things. At the start of those discussions, there were a number of countries, notably the United States, Great Britain, and West Germany, that all took the position that we should not have additional controls.

Now, the United States stands alone. West Germany changed its position in 1982, and adopted legislation in 1983, as I mentioned. Mrs. Thatcher's government, last fall, changed the British position, they are moving moving forward with a program of applying controls to existing plants. The United States stands alone in its policy of refusing to go forward with further emission reductions, and it is time to change that.

Senator **Stafford**. Thank you, Mr. Chairman.

Senator **Mitchell**. Thank you, Senator Stafford.

Senator **Graham**. Mr. Chairman, I was impressed with the statistics that Mr. Hawkins just gave as to the trendline. I wonder if those statistics are concurred in by EPA and the Department of Energy.

Mr. **Potter**. I think those basic trendlines, we agree with, Senator Graham. I think what we have here is the issue of growth, and

I think that this is something that Congress needs to consider. We are talking about that certainly in the context of ozone. We are going to be talking about it with regard to the other criteria pollutants that we have to deal with under the Clean Air Act in the future.

Senator GRAHAM. Does the Department of Energy concur in the statistics cited by Mr. Hawkins?

Ms. WALKER. No, I don't think so. I think that we have to recognize that future emissions depend on several factors, including demand for electricity, economic conditions, fuel choices, emission limits, the age of retirement, and the capacity utilization, none of these can be predicted precisely.

Any of the projections are a reflection of the assumptions made, and we would probably disagree with some of the assumptions made. Based on those, we have projected future emissions under a range of the assumptions, and believe that the trends are not those indicated.

Mr. WAMPLER. Senator, one point of clarification. I am told that we are in the process of reviewing those trendlines. I think in general we agree with them. We think that there may be some minor changes in them. Perhaps, we could indicate, for the record, the status of our review in some detail.

[DOE supplied the following information:]

FOSSIL ENERGY'S STATUS OF REVIEW OF TREND LINES

In general, we agree that these curves accurately reflect the assumptions which were used in the analysis. However, we feel that these are "worst-case" assumptions. Alternatively, and perhaps more likely, assumptions have generated trend lines which show small increases in SO_2 emissions, no increase, or substantial decreases, depending on the assumptions chosen. Clearly there is considerable uncertainty regarding these projections for the year 2010.

Senator GRAHAM. Mr. Chairman, could the committee ask Mr. Hawkins, EPA, and DOE for submission of their analysis and the assumptions upon which they are now conducted?

Senator MITCHELL. Indeed, we will do so, we will ask that you provide that information.

Ms. WALKER. We will be happy to.

[DOE supplied the following information:]

In response to the request of Senators Mitchell and Graham, the following DOE environmental trends are provided:

"Environmental Trends to the Year 2000, A Supplement to the National Energy Policy Required by Title VIII of the U.S. Department of Energy Organization Act (Public Law 95-91)," DOE/EP-0021, July 1981.

"Appendix B, Environmental Trends for the Best Estimate Scenario of the National Energy Policy Plan (to 2000);" DOE, Mitre Corporation and Control Data Corporation; July 24, 1981.

"Environmental Trends Associated with the Fifth Energy Policy Plan," ANL/EES-TM-323, August 1986.

All analytical assumptions are clearly defined in each report. The analyses of acid rain control proposals provided in response to Senator Stafford's request (page 243) also include emissions trends projections, with and without consideration of the impacts of the purposal.

[EPA supplied the following:]

Attached is EPA's interim base case forcast which includes a forcast SO_2 emissions and the assumptions supporting that forcast.

ICF INCORPORATED International Square 1850 K Street Northwest Washington D C 20006 (202) 862-1100

March 10, 1987

MEMORANDUM

TO: Paul Schwengels, EPA

FROM: Bruce Braine, ICF
Richard Stuebi

SUBJECT: Interim EPA Base Case Forecasts

This memorandum presents summary national and regional forecasts from the recently completed 1987 interim EPA Base Case. This base case was developed for use in the CEUM/AUSM comparison effort and for use in regulatory analyses prior to the development of the final EPA base.

This memorandum is divided into two sections. The first section briefly discusses the emission, generation, and coal production forecasts and trends. The second section notes the major differences between this interim 1987 EPA base and the 1985 EPA Base Case. Attachment A provides forecasts of utility SO2 and NOx emissions, emission rates, generation, fuel consumption, and coal production, while Attachment B presents detailed input specifications and assumptions for the preliminary 1987 EPA Base Case as compared to the previous 1985 EPA base.

INTERIM 1987 BASE CASE FORECASTS

Summary forecasts from the Interim Base Case are presented in Table 1. The findings indicate include:

- Sulfur dioxide emissions rise steadily throughout the forecast period, from 1985 "actual" levels of 16.3 million tons to an estimated 21.7 million tons by 2010. Most of this growth in the near term (1985-1995) is forecast to come from increased utilization of existing (pre-1986) coal fired plants and greater use of oil relative to gas at oil/gas steam units as gas prices firm relative to oil prices. After 2000, most growth will come from the addition of new coal fired powerplants.

- Utility sulfur dioxide emissions are forecast to increase by 2.3 million tons between 1985 and 1995, from 16.3 million tons to 18.6 million tons. This reflects:

  - A 1.5 million ton increase in emissions (from 15.7 million tons to 17.2 million tons) at existing (pre-1986) coal powerplants.
  - A 0.5 million ton increase in emissions (from 0.6 million tons to 1.1 million tons) from oil/gas units.
  - The addition of new coal-fired powerplants since 1985, which accounts for an estimated 0.2 million tons of sulfur dioxide by 1995.

- Higher emissions from existing coal plants in the near-term (1985-1995) are due to several factors. At present, a number of coal powerplants are being less-than-fully utilized primarily due to (1) excess coal capacity, associated with a large number of new coal-fired plants brought on-line during the 1980-85 period when there was relatively little electricity sales growth, (2) a large amount of new nuclear capacity recently brought on-line, which has also resulted in existing coal plants being utilized less, particularly in states such as Illinois, the Carolinas, and Pennsylvania. As electricity sales increase and the number of new nuclear and coal plants added begins to decline over this time frame, the coal capacity which is now relatively idle should be utilized more intensively.

- Higher emissions from oil/gas steam units will result from increased use of oil relative to gas as the gas "bubble" disappears and gas prices firm relative to oil prices.

- After 1995, sulfur dioxide emissions are expected to increase by an additional 3.1 million tons by 2010 (from 18.6 million tons to 21.7 million tons). This reflects:

  - An additional 1.5 million ton increase (from 17.2 million tons to 18.7 million tons) from existing coal powerplants by 2000 as existing plants are utilized more fully.
  - An increase of 1.8 million tons associated with the addition of new coal-fired units. Most of this increase occurs after 2000 when most of the new coal plants are built.
  - An 0.2 million ton decline (from 1.1 million tons to 0.9 million tons) at oil/gas plants as oil/steam plants are retired.

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- New coal sulfur dioxide emissions increase dramatically in the long-term (1995-2010) because 223 additional gigawatts of new coal capacity is forecast to be completed over this time period. Most new coal capacity is forecast to be built after 2000 (198 gigawatts) and reflects:

    - Coal capacity built to meet higher electricity demands (142 gigawatts).

    - Capacity built to replace retiring nuclear, coal, and oil/gas steam plants (42 gigawatts).

    - Capacity built to replace oil/gas steam capacity which, as oil prices rise, becomes increasingly expensive to operate (14 gigawatts).

  As a result of these coal builds, coal generation accounts for slightly more than half of all energy generated in 1995, but represents two-thirds of total generation in 2010. However, because new scrubbed coal capacity continues to increase its share of total coal capacity, the average coal sulfur dioxide emission rate is forecast to fall steadily, particularly as the older SIP units begin to retire with more frequency. Thus, coal SO2 emissions do not increase as rapidly as coal fired generation.

- Utility nitrogen oxide emissions are also forecast to rise significantly from 1980 to 2010. Moreover, total utility nitrogen oxide emissions are forecast to rise more quickly than sulfur dioxide emissions, especially between 2000 and 2010. While the average nitrogen oxide emission rate does decrease over time, it falls less significantly than the average sulfur dioxide emissions rate. This is because average NOx rates at existing units are only somewhat higher than new plant NOx limits, but SO2 rates at existing units are substantially higher than new plant SO2 rates. Therefore, nitrogen oxide emissions rise roughly in parallel with increases in coal and oil/gas generation, increasing from 1980 historical levels of 6.6 million tons to 11.3 million tons in 2010.

- Electricity generation is expected to grow at roughly the same rate as electricity sales. Both grow at roughly 2.2 percent annually through 1995, and 2.0 percent per year thereafter. Nuclear generation accounts for most of this growth through 1990, increasing by 60 percent (from 380 to 610 billion

TABLE 1

NATIONAL SUMMARY BASE CASE FORECASTS

	1980	1985	1990	1995	2000	2010
SO2 Emissions (millions of tons)						
Coal						
Existing[1]	16.02	15.69	16.78	17.23	17.87	18.74
New	-	-	0.10	0.20	0.43	2.01
Total	16.02	15.69	16.88	17.43	18.30	20.26
Oil/Gas	1.36	0.58	0.89	1.14	1.32	0.93
Total	17.38	16.27	17.77	18.57	19.62	21.69
NOx Emissions (millions of tons)						
Coal						
Existing[1]	5.44	NA	6.53	6.82	7.14	7.26
New	-	NA	0.16	0.26	0.65	3.52
Total	5.44	NA	6.70	7.08	7.79	10.77
Oil/Gas	1.18	NA	0.47	0.77	0.84	0.52
Total	6.62	NA	7.16	7.85	8.63	11.29
Utility Electricity Generation (trillions of kwh)						
Coal	1.16	1.40	1.50	1.58	1.78	2.79
Oil/Gas	0.59	0.39	0.22	0.38	0.44	0.29
Nuclear	0.25	0.38	0.61	0.62	0.62	0.46
Hydro & Other	0.28	0.30	0.41	0.48	0.53	0.58
Total	2.28	2.47	2.74	3.06	3.37	4.12
Coal Production (millions of tons)						
Northern Appalachia	185.1	161.5	174.4	179.9	187.8	258.0
Central Appalachia	232.8	244.8	244.3	282.4	330.4	406.9
Southern Appalachia	26.4	25.6	25.5	22.5	24.6	35.8
Midwest	134.4	133.3	130.8	124.8	142.6	175.0
West	251.0	315.9	389.6	428.3	479.2	777.2
Total	829.7	881.1	964.6	1037.9	1164.6	1652.9

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[1] "Existing" capacity defined as coal capacity which came on line prior to 12/31/85.

NA: Not Available.

kilowatt-hours) due to the many new nuclear units assumed to be brought on-line, as well as several others (notably, the TVA nuclear units) that are expected to be restarted. Oil/gas generation declines significantly as oil and gas prices rise from low levels in 1986, more nuclear plants are brought on-line, and excess coal capacity is used to displace more expensive oil/gas generation. As mentioned previously, coal generation rises steadily through 2010, as underutilized existing capacity is utilized more and new coal capacity is added. After 2000, coal generation jumps significantly (by about 57 percent) by 2010 to compensate for nuclear and oil/gas retirements and to meet higher sales demands.

- National coal production is forecast to increase in line with the growth in coal-fired generation, reflecting the high percentage of coal shipments that go to the utility sector (about 79 percent in 1985). Regional coal production growth varies considerably. For example, in two key producing areas:
    - Demand for coals from higher sulfur producing regions, such as the Midwest, is expected to remain approximately flat until 2000. This reflects the combination of several factors: (1) shifts away from Midwestern coals associated with tighter emission limits in Wisconsin and more economic use of Western coals in states such as Missouri, (2) a large amount of nuclear capacity built in regions using predominantly Midwestern coals (e.g., Illinois), and (3) some increases in demand in growing markets which burn Midwest coals such as Indiana and Kentucky. Until new scrubbed plants get built, mainly after 2000, there is relatively little growth in demand expected for these coals.
    - Coals from the West are forecast to experience a very high rate of demand growth, reflecting primarily (1) penetration into Midwestern markets such as Wisconsin and Missouri, and (2) growth in new coal capacity which is concentrated in the Western states and which will therefore be supplied by western coals.

COMPARISON OF THE INTERIM 1987 BASE WITH THE 1985 BASE

Table 2 compares the key 1995 forecasts from the interim 1987 EPA Base Case analysis with those developed for the previous 1985 EPA Base Case. Table 3 on pages 8 and 9 presents a comparison of major input assumptions for 1995 used in both base cases.

TABLE 2

COMPARISON OF INTERIM 1987 BASE FORECASTS WITH 1985 BASE FORECASTS - 1995

	Interim 1987 Base	1985 Base	Difference
SO2 Emissions (millions of tons)	18.6	19.7	-1.1
NOx Emissions (millions of tons)	7.8	8.4	-0.6
SO2 Emissions Rate (lbs. SO2 per MMBtu)	1.79	1.74	+0.05
NOx Emissions Rate (lbs. SO2 per MMBtu)	0.76	0.75	+0.01
Utility Electricity Generation (trillions of kwh)			
Coal	1.58	1.71	-0.13
Oil/Gas	0.38	0.43	-0.05
Nuclear	0.62	0.64	-0.02
Hydro & Other	0.48	0.38	+0.10
Total	3.06	3.16	-0.10
Coal Production (millions of Tons)			
Northern Appalachia	179.9	197.5	-17.6
Central Appalachia	282.4	306.6	-24.2
Southern Appalachia	22.5	25.1	-2.6
Midwest	124.8	150.5	-25.7
West	428.3	516.0	-87.7
Total	1037.9	1195.7	-157.8

Some of the key forecast differences are noted below:

- Sulfur dioxide emissions are lower in the more recent Base Case. This is primarily due to lower coal-fired generation (mostly because total generation and sales are lower and contributions from cogeneration and renewable sources are higher).
- Nitrogen oxide emissions are also forecast to be lower in the new case, largely as a result of lower fossil-fuel generation.
- Generation is lower due to lower assumed growth in electricity sales (2.2 percent per year through 1995 compared to 2.5 percent in the previous EPA base). Both coal and oil/gas generation fall proportionally more than total generation requirements because nuclear is relatively unchanged and cogeneration and renewables (such as municipal waste, small hydro, and geothermal) have increased significantly from the previous EPA base.
- Coal production is lower as a result of lower coal fired generation. Midwest and Western coals are reduced the most because these coals are generally burned in newer plants, and fewer new plants are built by 1995.

TABLE 3

COMPARISON OF MAJOR BASE CASE ASSUMPTIONS - 1995

	Interim 1987 Base	1985 Base	Comments
U.S. Electricity Sales (trillions of kwh)	2.86	2.97	Lower sales results a 2.2 percent per year growth rate vs. a 2.5 percent in the previous base.
Imports of Canadian Electricity (billions of kwh)	64	90	Lower imports reflect recent ICF assessments of transmission capabilities and available capacity in Canada.
World Oil Price (early 1986 $/bbl)	23.60	35.10	Lower oil prices reflect the large decline in oil prices which occurred since the development of the 1985 Base Case.
Coal Reconversions (Gw) 1986-1995	1.2	6.4	Fewer reconversions reflect recent cancellations largely associated with lower oil prices.
Cogeneration & Other Renewables (billions of kwh)	185	90	More cogeneration and other Q.Fs based on continuing ICF assessments of the markets.
Non-Utility Coal Demand (millions of tons)	204	306	Lower non-utility demand largely reflects lower forecasted industrial demand primarily due to lower oil and gas prices reducing the number of new coal boilers and coal conversions.
Emission Regulations (lbs. SO2/MMBtu)			
Wisconsin coal plants:			Tighter limits in Wisconsin reflect finalization of SIP regulations. Cumberland limit changed due to information obtained from TVA.
Alma #1-5	1/	4.00	
Columbia #1	2.12	4.00	
Dewey #1-2	1/	4.78	
Genoa #6	1/	4.00	
Oak Creek #1-8	3.20	4.00	
Rock River #1-2	3.20	4.00	

TABLE 3 (Continued)

COMPARISON OF MAJOR BASE CASE ASSUMPTIONS - 1995

	Interim 1987 Base	1985 Base	Comments
Emission Regulations (Continued)			
Burger #1-5 (Ohio Edison)	9.02	No Limit	
Cumberland #1-2 (TVA)	5.00	4.20	

1/ These units burn both bituminous and subbituminous coals. The bituminous is limited to 3.86 lbs. SO2/MMBtu, while the subbituminous is limited to 1.66 lbs. SO2/MMBtu.

ATTACHMENT A

FORECASTS FROM THE INTERIM 1987 EPA BASE CASE

1990-2010

TABLE A-1

UTILITY SULFUR DIOXIDE EMISSION FORECASTS

			EPA Base Case			
	1980	1985	1990	1995	2000	2010
Utility SO2 Emissions (millions of tons)						
31-Eastern States						
Coal						
Existing[1]	14.92	14.21	14.88	15.26	15.85	16.76
New - NSPS	-	-	0.05	0.13	0.20	0.20
New - ANSPS	-	-	0.01	0.01	0.14	1.27
Total	14.92	14.21	14.94	15.41	16.20	18.23
Oil/Gas	1.27	0.57	0.77	1.02	1.19	0.82
Total 31-Eastern States	16.19	14.78	15.71	16.43	17.39	19.05
17-Western States						
Coal						
Existing[1]	1.10	1.48	1.92	2.00	2.05	2.01
New - NSPS	-	-	0.02	0.02	0.02	0.02
New - ANSPS	-	-	0.02	0.02	0.06	0.53
Total	1.10	1.48	1.96	2.05	2.13	2.56
Oil/Gas	0.09	0.01	0.12	0.12	0.13	0.11
Total 17-Eastern States	1.19	1.49	2.08	2.17	2.26	2.67
Total U.S.						
Coal						
Existing[1]	16.02	15.69	16.80	17.26	17.90	18.77
New - NSPS	-	-	0.07	0.16	0.22	0.22
New - ANSPS	-	-	0.03	0.04	0.21	1.79
Total	16.02	15.69	16.90	17.46	18.33	20.79
Oil/Gas	1.36	0.58	0.89	1.14	1.32	0.93
Total U.S.	17.38	16.27	17.79	18.60	19.65	21.72

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[1] Designated existing capacity as of 12/31/85. Represents emissions from all existing coal capacity, including emissions from NSPS and ANSPS units.

TABLE A-2

UTILITY SULFUR DIOXIDE EMISSION RATE FORECASTS

			EPA Base Case			
	1980	1985	1990	1995	2000	2010
Utility SO2 Emission Rates						
(lbs. SO2/MMBtu)						
31-Eastern States						
Coal						
Existing[1]	3.13	2.57	2.62	2.56	2.52	2.60
New - NSPS	-	-	0.99	0.85	0.88	0.95
New - ANSPS	-	-	0.35	0.31	0.33	0.35
Total	3.13	2.57	2.60	2.50	2.33	1.77
Oil/Gas	0.85	0.62	1.50	0.95	0.96	0.86
Total 31-Eastern States	2.58	2.25	2.51	2.27	2.12	1.69
17-Western States						
Coal						
Existing[1]	0.85	0.83	0.97	0.98	0.98	0.99
New - NSPS	-	-	0.46	0.46	0.46	0.46
New - ANSPS	-	-	0.17	0.20	0.19	0.25
Total	0.85	0.83	0.92	0.92	0.86	0.61
Oil/Gas	0.06	0.01	0.20	0.13	0.13	0.18
Total 17-Eastern States	0.42	0.53	0.76	0.69	0.65	0.56
Total U.S.						
Coal						
Existing[1]	2.64	2.15	2.19	2.15	2.14	2.21
New - NSPS	-	-	0.72	0.76	0.81	0.86
New - ANSPS	-	-	0.21	0.23	0.27	0.31
Total	2.64	2.15	2.14	2.08	1.95	1.44
Oil/Gas	0.45	0.28	0.79	0.58	0.58	0.60
Total U.S.	1.90	1.73	1.97	1.79	1.68	1.35

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[1] Designated existing capacity as of 12/31/85. Represents emissions from all existing coal capacity, including emissions from NSPS and ANSPS units.

TABLE A-3

UTILITY NITROGEN OXIDE EMISSION FORECASTS [1]

	1980	EPA Base Case			
		1990	1995	2000	2010
Utility NOx Emissions (millions of tons)					
31-Eastern States					
Coal					
Existing[2]	4.55	5.12	5.36	5.66	5.81
New - NSPS	-	0.04	0.11	0.16	0.15
New - ANSPS	-	0.02	0.03	0.26	2.10
Total	4.55	5.18	5.50	6.08	8.06
Oil/Gas	0.57	0.19	0.42	0.43	0.29
Total 31-Eastern States	5.12	5.37	5.91	6.51	8.36
17-Western States					
Coal					
Existing[2]	0.89	1.41	1.46	1.49	1.45
New - NSPS	-	0.04	0.04	0.04	0.04
New - ANSPS	-	0.07	0.08	0.19	1.23
Total	0.89	1.52	1.58	1.71	2.71
Oil/Gas	0.61	0.27	0.36	0.41	0.22
Total 17-Eastern States	1.50	1.79	1.93	2.12	2.93
Total U.S.					
Coal					
Existing[2]	5.44	6.53	6.82	7.14	7.26
New - NSPS	-	0.07	0.15	0.20	0.19
New - ANSPS	-	0.09	0.11	0.45	3.33
Total	5.44	6.70	7.08	7.79	10.77
Oil/Gas	1.18	0.47	0.77	0.84	0.52
Total U.S.	6.62	7.16	7.85	8.63	11.29

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[1] Data for 1985 not available.

[2] Designated existing capacity as of 12/31/85. Represents emissions from all existing coal capacity, including emissions from NSPS and ANSPS units.

TABLE A-4

UTILITY NITROGEN OXIDE EMISSION RATE FORECASTS

	1980	EPA Base Case 1990	1995	2000	2010
Utility NOx Emission Rates (lbs. NOx/MMBtu)					
31-Eastern States					
Coal					
Existing[2/]	0.96	0.90	0.90	0.90	0.90
New - NSPS	-	0.75	0.71	0.71	0.71
New - ANSPS	-	0.60	0.60	0.60	0.58
Total	0.96	0.90	0.89	0.87	0.78
Oil/Gas	0.38	0.38	0.39	0.34	0.31
Total 31-Eastern States	0.82	0.86	0.82	0.79	0.74
17-Western States					
Coal					
Existing[2/]	0.69	0.71	0.71	0.71	0.71
New - NSPS	-	0.75	0.75	0.75	0.75
New - ANSPS	-	0.64	0.66	0.57	0.58
Total	0.69	0.71	0.71	0.69	0.65
Oil/Gas	0.40	0.45	0.40	0.39	0.38
Total 17-Eastern States	0.53	0.65	0.62	0.61	0.61
Total U.S.					
Coal					
Existing[2/]	0.90	0.85	0.85	0.85	0.86
New - NSPS	-	0.75	0.72	0.72	0.72
New - ANSPS	-	0.63	0.64	0.59	0.58
Total	0.90	0.85	0.84	0.83	0.74
Oil/Gas	0.39	0.42	0.39	0.37	0.33
Total U.S.	0.73	0.79	0.76	0.74	0.70

[1/] Data for 1985 not available.

[2/] Designated existing capacity as of 12/31/85. Represents emissions from all existing coal capacity, including emissions from NSPS and ANSPS units.

TABLE A-5

TOTAL UTILITY POWERPLANT CAPACITY
(Gigawatts)

	1980	1985	EPA Base Case 1990	1995	2000	2010
Coal						
Existing[1]	245.7	286.7	287.8	287.8	287.6	282.7
New - NSPS	-	-	3.4	7.0	9.4	9.4
New - ANSPS	-	-	5.0	5.9	28.2	225.9
Total	245.7	286.7	296.1	300.7	325.2	518.0
Oil/Gas Steam	166.4[2]	205.2[2]	149.0	149.0	148.9	139.7
Oil/Gas Turbine & Combined Cycle			54.4	55.0	64.1	75.5
Nuclear	56.5	75.7	103.2	106.4	106.2	78.2
Hydro & Other	76.3	83.6	108.3	116.6	124.5	132.8
Total	542.8	651.2	711.0	727.6	768.9	944.2

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[1] Designated existing capacity as of 12/31/85. Represents total existing coal capacity, including NSPS and ANSPS units. Existing coal capacity increases between 1985 and 1990 due to reconversions of oil capacity to coal.

[2] Represents total oil/gas capacity, including oil/gas turbines and combined cycle capacity.

TABLE A-6

TOTAL UTILITY ELECTRICITY GENERATION
(Trillion Kwh)

			EPA Base Case			
	1980	1985	1990	1995	2000	2010
Coal						
Existing[1]	1.16	1.40	1.45	1.51	1.57	1.59
New - NSPS	-	-	0.02	0.04	0.05	0.05
New - ANSPS	-	-	0.03	0.03	0.15	1.14
Total	1.16	1.40	1.50	1.58	1.78	2.79
Oil/Gas Steam	0.59[2]	0.39[2]	0.19	0.34	0.38	0.21
Oil/Gas Turbine & Combined Cycle			0.03	0.04	0.06	0.08
Nuclear	0.25	0.38	0.61	0.62	0.62	0.46
Hydro & Other	0.28	0.30	0.41	0.48	0.53	0.58
Total	2.28	2.47	2.74	3.06	3.37	4.12

---

[1] Designated existing capacity as of 12/31/85. Represents total existing coal capacity generation, including NSPS and ANSPS unit generation.

[2] Represents total oil/gas capacity generation, including oil/gas turbine and combined cycle generation.

TABLE A-7

UTILITY FUEL CONSUMPTION FORECASTS
(Quads)

Utility Fuel Consumption	1980	1985	EPA Base Case 1990	1995	2000	2010
31-Eastern States						
Coal						
Low Sulfur	0.87	1.89	2.13	2.63	3.35	6.82
Low-Medium Sulfur	1.61	1.56	2.03	2.08	2.65	3.82
High-Medium Sulfur	3.18	3.66	3.51	3.82	3.78	4.86
High Sulfur	3.86	3.90	3.85	3.81	4.11	5.08
Total	9.53	11.01	11.51	12.34	13.90	20.57
Oil	1.99	0.93	1.03	1.54	1.98	1.79
Gas	1.01	0.92	0.18	0.79	0.71	0.44
17-Western States						
Coal						
Low Sulfur	1.41	1.61	2.36	2.42	2.71	5.56
Low-Medium Sulfur	0.43	0.94	0.80	0.85	0.95	1.55
High-Medium Sulfur	0.74	0.96	1.06	1.11	1.22	1.21
High Sulfur	0.01	0.07	0.06	0.07	0.06	0.08
Total	2.59	3.58	4.28	4.44	4.93	8.40
Oil	0.48	0.06	0.23	0.24	0.28	0.34
Gas	2.58	2.28	1.07	1.64	1.90	0.99
Total U.S.						
Coal						
Low Sulfur	2.28	3.50	4.50	5.06	6.06	12.38
Low-Medium Sulfur	2.04	2.49	2.83	2.93	3.60	5.37
High-Medium Sulfur	3.92	4.62	4.57	4.94	4.99	6.06
High Sulfur	3.87	3.97	3.91	3.87	4.18	5.16
Total	12.12	14.58	15.80	16.79	18.84	28.96
Oil	2.47	0.99	1.26	1.79	2.26	2.13
Gas	3.59	3.20	1.25	2.43	2.61	1.44

TABLE A-8

COAL PRODUCTION AND SHIPMENT FORECASTS
(Millions of Tons)

	1980	1985	EPA Base Case 1990	EPA Base Case 1995	EPA Base Case 2000	EPA Base Case 2010
Coal Production						
Northern Appalachia	185.1	165.5	174.4	179.9	187.8	258.0
Central Appalachia	232.8	244.8	244.3	282.4	330.4	406.9
Southern Appalachia	26.4	25.6	25.5	22.5	24.6	35.8
Midwest	134.4	133.3	130.8	124.8	142.6	175.0
West	251.0	315.9	389.6	428.3	479.2	777.2
Total U.S.	829.7	881.1	964.6	1037.9	1164.6	1652.9
Coal Transportation						
Western Coal Shipped East	36.7	32.2	44.0	54.7	69.6	183.3
Eastern Coal Shipped West	25.0	30.0	24.9	30.6	38.3	42.3
Coal Production by State						
Northern Appalachia						
Pennsylvania	93.1	65.3	70.2	74.2	86.7	133.7
Ohio	39.4	35.7	38.2	33.5	32.5	37.2
Maryland	3.8	2.8	3.6	3.0	2.5	1.9
No. W. Virginia	48.8	56.9	62.4	69.1	66.1	85.1
Total	185.1	161.5	174.4	179.9	187.8	258.0
Central Appalachia						
So. W. Virginia	72.7	70.7	83.2	92.6	134.0	188.0
Virginia	41.0	43.9	45.9	51.2	68.7	69.6
East Kentucky	109.2	121.7	108.7	130.7	114.0	126.5
Tennessee	9.9	7.5	6.5	7.9	13.8	22.9
Total	232.8	244.8	244.3	282.4	330.4	406.9
Midwest						
Illinois	62.5	61.1	58.4	58.1	82.0	100.5
Indiana	30.9	34.0	31.4	25.9	21.4	27.4
West Kentucky	41.0	38.2	40.9	40.8	39.3	47.2
Total	134.4	133.3	130.8	124.8	142.6	175.0

TABLE A-9

UTILITY SO2 EMISSIONS BY REGION
(Thousands of Tons)

Region	1980	1985	EPA Base Case 1990	1995	2000	2010
Maine/Vt/NH	97	86	55	70	70	81
Mass/Conn/Rhode Island	292	288	270	289	336	376
New York	479	420	369	481	518	543
Pennsylvania	1422	1320	1152	1275	1186	1232
New Jersey	103	97	96	130	127	191
Maryland/Delaware	277	281	311	378	396	409
Virginia	157	131	195	240	293	341
West Virginia	984	969	1002	961	1007	1037
N. & S. Carolina	655	500	660	689	728	968
Georgia	704	976	864	874	946	1021
Florida	692	501	898	937	968	910
Ohio	2185	2193	2710	2572	2677	2849
Michigan	608	401	429	449	477	516
Illinois	1110	1054	831	955	1096	1407
Indiana	1672	1498	1668	1710	1782	2007
Wisconsin	488	367	333	273	267	327
Kentucky	1029	745	869	893	935	941
Tennessee	910	802	875	856	922	1056
Alabama	535	563	444	512	565	595
Mississippi	122	113	140	146	153	168
Minnesota	160	124	145	169	218	216
Iowa	236	219	213	302	368	438
Missouri	1227	997	973	1056	1118	1196
Arkansas	27	69	123	125	151	131
Louisiana	21	67	88	86	84	89
Total 31-Eastern States	16,193	14,781	15,712	16,431	17,387	19,047

TABLE A-9 (Continued)

UTILITY SO2 EMISSIONS BY REGION
(Thousands of Tons)

Region	1980	1985	EPA Base Case 1990	1995	2000	2010
N. & S. Dakota	109	156	219	227	239	302
Kansas/Nebraska	149	211	304	340	351	365
Oklahoma	45	80	218	209	225	225
Texas	295	430	651	695	710	890
Montana	23	22	45	45	48	64
Wyoming	128	135	63	62	70	68
Idaho	-	-	-	-	-	-
Colorado	71	84	127	130	137	145
New Mexico	78	114	56	56	56	57
Utah	25	27	67	69	70	77
Arizona	84	104	124	126	130	138
Nevada	38	35	75	76	79	78
Washington/Oregon	72	88	132	130	149	237
California	70	3	-	-	-	20
Total 17-Western States	1,187	1,489	2,081	2,166	2,263	2,668
Total U.S.	17,380	16,270	17,793	18,597	19,650	21,715

Note: Totals may not add due to independent rounding.

TABLE A-10

UTILITY NOX EMISSIONS BY REGION [1/]
(Thousands of Tons)

Region	1980	EPA Base Case			
		1990	1995	2000	2010
Maine/Vt/NH	32	25	32	31	49
Mass/Conn/Rhode Island	81	94	110	125	263
New York	146	127	173	221	376
Pennsylvania	417	370	420	384	393
New Jersey	81	53	90	100	202
Maryland/Delaware	91	116	134	150	227
Virginia	66	79	96	137	225
West Virginia	319	371	353	376	383
N. & S. Carolina	352	331	342	407	608
Georgia	235	234	249	268	343
Florida	242	306	328	395	462
Ohio	526	618	612	639	790
Michigan	262	292	303	333	436
Illinois	396	277	327	392	612
Indiana	411	451	515	530	566
Wisconsin	132	152	174	191	248
Kentucky	278	353	372	413	416
Tennessee	215	241	240	256	478
Alabama	188	173	196	234	253
Mississippi	57	52	53	56	105
Minnesota	98	112	130	155	136
Iowa	92	101	111	131	161
Missouri	270	287	321	334	384
Arkansas	26	80	81	91	89
Louisiana	98	79	150	158	153
Total 31-Eastern States	5,116	5,374	5,914	6,505	8,358

TABLE A-10 (Continued)

UTILITY NOX EMISSIONS BY REGION [1]
(Thousands of Tons)

Region	1980	EPA Base Case 1990	1995	2000	2010
N. & S. Dakota	77	121	126	134	257
Kansas/Nebraska	140	194	218	219	215
Oklahoma	127	142	142	153	207
Texas	544	580	655	720	970
Montana	20	55	55	71	76
Wyoming	96	136	136	158	157
Idaho	-	-	-	-	-
Colorado	98	136	137	146	176
New Mexico	75	80	81	80	83
Utah	40	98	98	99	132
Arizona	89	113	117	127	168
Nevada	42	67	68	79	91
Washington/Oregon	29	45	46	76	247
California	132	23	57	61	154
Total 17-Western States	1,505	1,790	1,935	2,122	2,933
Total U.S.	6,621	7,164	7,849	8,628	11,291

Note: Totals may not add due to independent rounding.

[1] 1985 data not available.

ATTACHMENT B

MAJOR ASSUMPTIONS IN THE INTERIM 1987 EPA BASE CASE

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
ELECTRIC UTILITY ENERGY DEMAND			
o World Oil Prices (early 1986 $/bbl)			
1990	17.80	30.10	New case reflects latest ICF analyses and assumes modest real increase in oil prices through 1990 and 3 percent per year growth in the long term.
1995	23.60	35.10	
2000	27.40	40.10	
2010	36.80	51.30	
o Electricity Growth (% Per Year)			
1986-1995	2.2	2.5	New case reflects EPA assumptions.
1995-2010	2.0	2.5	
o Total U.S. Nuclear Capacity (Gw)			
1990	103	105	Capacity in proposed case is now lower due to some nuclear postponements and cancellations and reflecting the TVA nuclear plant shut downs. In 2010, no new nuclear plants are built to replace retirements.
1995	106	108	
2000	106	109	
2010	79	120	
o Nuclear Capacity Factors (%)			
1985	61	60	
1990	67	64	
1995	67	67	
2000	67	67	
2010	67	67	
o Substitution of Coal for Oil and Gas (Gw)			
Reconversions 1986-1995	1.2	6.4	The new case reflects most recent cancellations.
o Utility Capital Costs (1986 $/kw)			
Coal	900-1,010	990-1,175	Costs no longer include 10% real escalation. Powerplant costs shown her do not include charges for transmission hookup.
Nuclear	1,725-1,960	1,898-2,156	
Turbine	275- 315	302- 346	
Dry Scrubbers, New	99- 112	109- 123	
Wet Scrubbers, New	204- 245	224- 269	

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES (Continued)

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
ELECTRIC UTILITY ENERGY DEMAND (Continued)			
o Powerplant Lifetime (Years)			
Coal Steam	60	60	Coal and oil/gas steam powerplants are refurbished after 30 years for $200/kw (early 1986 $). This is assumed to extend their useful lifetime from 45 to 60 years. Reconversions are assumed to retire 30 years after their reconversion date.
Oil/Gas Steam	60	45	
Nuclear	35	35	
Oil/Gas Turbine	20	20	
o Coal Powerplant Heat Rates Over Time	0.25% per year increase over current levels. After refurbishment, heat rates are improved (decreased) by five percent.	SAME	Based on empirical studies and engineering assessments of heat rate deterioration over time and the effects of powerplant refurbishment.
o Minimum Turndown Rates	Coal :35% Oil/Gas Steam:20%	SAME	Coal and oil/gas steam units must operate at or above minimum load.
o Cogeneration (bkwh)	1990 = 85	1990 = 77	Latest ICF analysis of cogeneration facilities are used in the new case.
	1995 = 117	1995 = 99	
	2000 = 154	2000 = 125	
	2010 = 194	2010 = 149	
o Canadian Power Imports (bkwh)			
1990	68	69	The new case reflects latest ICF analyses.
1995	64	90	
2000	76	87	
2010	75	97	

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES (Continued)

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
NON-UTILITY COAL DEMAND			
o Industrial/Retail Coal Use (millions of tons)	1990 = 87 1995 = 91 2000 = 98 2010 = 137	1990 = 109 1995 = 135 2000 = 170 2010 = 220	Latest forecast of ICF Industrial Boiler Model (IBM) combined with latest ICF forecast of the kiln and residential/commercial coal markets. Lower numbers reflect effects of lower oil and gas price forecasts. After 1990, large industrial boilers (greater than 100 MMBtu/hr) are assumed to be required to scrub.
o Coal Exports (millions of tons)			
-- Steam Coal	1990 = 24 1995 = 32 2000 = 35 2010 = 35	1990 = 25 1995 = 48 2000 = 69 2010 = 120	Latest ICF forecasts are used in the new case.
-- Metallurgical Coal Exports	1985 = 56 1990 = 49 1995 = 45 2000 = 40 2010 = 30	1985 = 53 1990 = 49 1995 = 53 2000 = 61 2010 = 65	Latest ICF forecasts are used in the new case.
o Domestic Metallurgical Coal Use (millions of tons)	1985 = 45 1990 = 37 1995 = 35 2000 = 32 2010 = 29	1985 = 54 1990 = 61 1995 = 62 2000 = 62 2010 = 62	Continuing trends in steel substitution limit forecasted domestic metallurgical coal use through most of the 1980s. Import reductions programs are now assumed to have less effect.
o Synthetics (Coal Input in millions of tons)	1990 = 6 1995 = 1 2000 = 1 2010 = 1	1990 = 8 1995 = 8 2000 = 8 2010 = 8	Outlook for coal-based projects continues to be unfavorable. Current forecast includes continued operation of the Great Plains gasification plant through 1990.
COAL SUPPLY PARAMETERS			
o Coal Transportation Rates (% Annual Real Escalation)			
-- Rail	Long-run marginal costs based on engineering	1981-1985 = -5.0% 1986-2000 = 0.0%	We have lowered our estimates of rail costs based on analysis of engineering and other cost data.

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COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES (Continued)

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
COAL SUPPLY PARAMETERS (Continued)			
-- Truck; Barge	Long-run marginal costs based on engineering analysis	1981-1985 = 5.0% 1986-2000 = 0.0%	
o Mining Costs (% Annual Real Escalation)	Capital = 0.0% Labor 1984-1987 = 1984 Contracts 1987-on = 2% per year	Capital = 1.0% Labor 1984-1987 = 1.0% 1987-on = 2.0%	Labor rates until 1987 reflect 1984 contract. Real escalation depends upon inflation. Deep mine productivity now assumed to increase at 3% per year in new case.
	Materials = 0.0%	Materials = 0.0% Productivity = 1-2%	
	Deep Productivity = 3%		
	Surface Productivity = 2%		
OTHER GOVERNMENTAL REGULATIONS			
o Federal Leasing Policy	Enough	Enough	Federal leasing is assumed to be sufficient to avoid artificially driving up market prices.
o Air Pollution Regulations	Most recent federal and state rules, including proposed changes in state SIPs and state acid rain programs. No changes in limits associated with tall stack regulations. Large industrial boilers must scrub by 1990.	Most recent federal and state rules. SO2 emission limits assumed to be tightened in New and Wisconsin over the next ten years.	

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES
(Continued)

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
FINANCIAL PARAMETERS			
o Tax Depreciation Life (years)			Tax depreciation based on ACRS of 1981 ERTA for 1985 EPA Base Case. New tax act requires 150% declining balance depreciation and results in removal of the five year rapid write-off provision for retrofit pollution control.
Retrofit Pollution Control	15	5	
Others	15	15	
o Real Discount Rates (% Per Year)	Coal Mine = 6.00% Utility = 4.27%	SAME	
o Real Capital Charge Rates			New charge rates are higher under the new tax law due to the elimination of the Investment Tax Credit and changes in tax depreciation which slightly offset the impacts of a lower tax rate.
Coal/Nuclear/Combined Cycle	9.4%	9.0%	
New Scrubbers/Particulate Equipment	9.4%	9.0%	
Combustion Turbines	11.3%	10.5%	
Retrofit Scrubbers	9.0%	6.5%	
o Book Life (years)			
Coal/Nuclear/Combined Cycle	30	SAME	
Combustion Turbine	20		
Pollution Control-Retrofit	30		
Pollution Control-New	30		
o Input Year Dollars	Early 1986	Early 1980	
o Output Year Dollars	Mid 1987	Early 1985	
o Escalation Input to Output Dollars	1.045	1.34	

Senator GRAHAM. I would like to return to a line of questioning that I was asking in the first round, and that has to do with the criteria for the selection or the request for submission to projects in Phase II.

The Envoys' report does seem to be quite clear, on pages 29 and 30, as to the characteristics of research technology. Why were those characteristics not indicated to potential applicants as standards that would most likely lead to their project being favorably considered?

Mr. WAMPLER. As presently envisioned, Clean Coal Technology II will be targeted to the recommendations of the Envoys' report. In fiscal year 1988, we are anticipating $150 million for, again, retrofit, repowering, and modernizing existing facilities. Again, an additional $200 million between 1990 and 1992 would be aimed at the same thing, with the caveat that they would focus on technologies that were still in the development process. We think it does, to that extent, focus on the Lewis-Davis recommendations criteria.

Senator GRAHAM. It seems to me that a very direct way to indicate that there are serious intensions to pursue this report would be to outline in the initial request for applications the standards set in the Envoys' report, and state that we are looking for applications, and the applications that meet the standards will be given priority in their likelihood of being funded.

Mr. WAMPLER. Again, we did not want to restrict the number and types.

Senator GRAHAM. I would not consider it to be a restriction, but I would consider it to be an encouragement for those entities that felt they had technologies that could, in fact, these standards and come forward with it.

Mr. WAMPLER. I understand your point.

Senator MITCHELL. You see, Senator, the reason is that this is a shell game. The Administration is playing a shell game. The Clean Coal program existed before the Envoys 'report. President Reagan promised Prime Minister Mulroney a $5 billion program funded half by the government, and that was to appease the Canadians.

When he got back here, they said, we can't spend all that money. What are we going to do? Someone said, look, we have had this Clean Coal program all these years, and we spent a lot of money there. Why don't we claim credit for that?

That is what they are doing. They are telling the Canadians. In fact, the day the announcement was made, Larry Speakes said, "It will be new funding in the future." The President wholly endorsed it to appease the Canadians. Now back here, it is not new funding, it is trying to take credit for all this old funding that has occurred prior to this. Therefore, they are now trying to stretch these to make them look like they overlap. That is the problem that Mr. Wampler has, and that is why Phase II is moving in this direction.

That is really the explanation of what they are doing. This is a shell game. We will see now, since this has been well stated and stated again, and I assume that there are some Canadian reporters in the room, that when Prime Minister Mulroney gets to meet with the President on April 5th, whether he is going to fall for this again.

Ms. **Walker**. Mr. Chairman, if you would like, I have the statement of the White House made at the time that it endorsed the Report. I believe that it reflects the ongoing programs at that time and says that we do not now have all of the funds, but it certainly recognizes that the Clean Coal Technology Program is a partial commitment to that effort.

Senator **Mitchell**. But he said that it will be funding in the future. It was a very clear statement, and they were talking about new money.

Ms. **Walker**. It said, "We do not now have all of the funds, but the Administration will seek to provide in the future the funding recommended."

Senator **Mitchell**. That is right.

Ms. **Walker**. Some of it was already there.

Senator **Mitchell**. Go ahead, Senator Graham.

I come back to you later, Ms. Walker.

Senator **Graham**. I think that the chairman shows his versatility in being both an effective witness as well as an interrogator.

In conclusion, it seems to me that whatever the history of this is, for the future there will be both scientific value and protocol value to our Canadian friends if we were to indicate that our seriousness of intention by stating that those applications, which meet the criteria of the Envoys' report, if not the only ones considered, at least would be given some additional points towards their likelihood of being selected.

I have no further questions.

Senator **Mitchell**. Thank you very much, Senator.

Let me go back to that, that was going to be my next question, Mr. Wampler.

As you know, the Envoys' report was submitted after DOE began to implement the Clean Coal program. As the Congressional Research Service has indicated in its analysis of the two programs, the Envoys' report sought short term reductions in emissions and commercialization of a cheaper alternative to scrubbers. The Clean Coal program was designed to assure the long term viability of the high sulfur coal industry.

On what basis can you claim that the preexisting Clean Coal program satisfies the requirements of the Envoys' report, which was subsequent to that program, which clearly has different objectives?

Mr. **Wampler**. I don't think that we claim that it met all the requirements of the Report. Let me answer that in a little bit different way.

I think that what we have tried to show in several ways, one of which is "America's Clean Coal Commitment", that there has been a tremendous amount of money spent in this country by utilities and others to clean up the environment. That is point number one.

Point number two is that we tried to make the point to the Canadians that there have been funds expended, as I recall, on the order of about $6.1 or $6.8 billion, that would apply to the criteria.

I have a press release that came from the Canadian Embassy on January 23d, and it really clarifies what their position is in regard to those numbers that we had talked to them about. What they say in one paragraph is that about $5 billion in projected U.S. Federal, State, and private sector expenditures for 1992 appear to be directed at demonstrated cleaner, more cost effective technologies, thereby meeting one or more of the Special Envoys' criteria. But only about $1.7 billion of the expenditures appear to meet most of the Special Envoys' technical criteria.

So you see, there is some credit being given there by the Canadians.

Senator **Mitchell**. I think that they are trying to make the point that $1.7 billion is a long way from $2.5 billion.

Mr. **Wampler**. It certainly is, and I don't think that we have ever made the point that the total expenditures have been made, at least I haven't.

I think that we have to look at this in terms of budget constraints. I think that there are viable projects ongoing. Clean Coal Technology II and III will move us closer to our goal.

Senator **Mitchell**. Let me ask you, Mr. Wampler.

Did you want to say something?

Mr. **Hawkins**. If I might, Mr. Chairman, I would just like to read the two sentences that follow immediately in the Canadian press release from what Mr. Wampler just read.

Senator **Mitchell**. Go ahead.

Mr. **Hawkins** [reading]:

> In the criteria of most significance to Canada, a reduction in transboundary acid rain causing emissions is the very one to which the U.S. program is least relevant. As a result, the potential reduction in U.S. transboundary flows will be negligible, and will not alleviate the damage inflicted on Canada by emissions from that country.

Senator **Mitchell**. Thank you very much, that places the whole statement in context now.

In his statement, Mr. Hawkins referred to West Germany and said that every large coal-fired plant in Germany, which will operate past 1993, is being required to install and operate a high efficiency scrubber by the beginning of 1988. He goes on to suggest that the cost there is $100 per kilowatt.

In your statement, you said, "Capital costs for adding scrubbers on older plants can equal or exceed the original plant investment." You provide no information on scrubber costs.

My question is, if it is $100 in West Germany, is it more than that here and, if so, why?

Mr. **Wampler**. I will let one of my technical people answer that directly, but if I might, let me make a couple of points.

If you look at it in terms of the cost of electricity in mils, what we project is that the conventional flue gas scrubber is likely to raise the cost of electricity by nine to eleven mils per kilowatt hour and thus, the capital cost by $180 to $200 per kilowatt hour.

If you look at some of the benefits of the technologies that will apply in repowering——

Senator **Mitchell**. You are using a figure of $180 to $200.

Mr. **Wampler**. Yes, $180 to $200 in capital costs.

If you look at some of the repowering technologies, with the coal gasifier gas turbine, we are projecting a one to two mil per kilowatt hour increase, with sulfur emissions that are reduced by 99 percent. If we are looking at pressurized fluidized bed, we are looking at a four to six mils increase per kilowatt hour at a substantial emissions reduction. The cheapest option in terms of capital costs is atmospheric fluidized bed. You get much less decrease in power output, so you are looking at six to eight mils per kilowatt hour. Our projections show these to be very substantial differences.

Senator MITCHELL. My time is up, and I will go to Senator Stafford. I will just note, Mr. Wampler, that the Electric Power Research Institute, and that is the research organization of the domestic utility industry, in October, 1986, estimated that scrubber costs for a new 500-megawatt high sulfur coal system is $129 per kilowatt hour.

Senator Stafford.

Senator STAFFORD. Thank you, Mr. Chairman.

I noticed your concern earlier, Mr. Chairman, about the speed of complying with the Lewis-Davis report and the recommendations. It has occurred to me, and I make this observation somewhat lightheartedly, that Admiral Poindexter and Colonel North aren't doing much these days.

In a more serious vein, both the United States and Canada should review their existing air pollution programs and legislate to identify opportunities consistent with existing law for addressing environmental concerns related to transboundary air pollution. This is part of the recommendations of the Lewis-Davis report.

The results of these reviews should be made available to the chief environmental officials of both countries for their consideration in the management of their respective programs.

Might I ask the panel what specifically has been done to implement this recommendation?

Mr. POTTER. Senator Stafford, perhaps I can respond to that since we have the lead responsibility there in the context of the bilateral activities with the Canadians.

We have finished the review of existing authorities. We have a draft document that is now being circulated to other agencies in the government. We are working through the process of finalizing that document. It will be part of the bilateral process, and we will decide then what we do with it in the context of the Envoys' recommendations.

Senator STAFFORD. Any other comments?

[No response.]

Senator STAFFORD. Since this is a hearing on the Clean Coal Technology program, it is logical that most of the attention is focusing on ways of reducing air pollution through machinery, but there are other options such as switching to natural gas or low sulfur coal.

In addition, we could establish a system of using our cleanest powerplants first, and the dirtiest ones last, rather than establishing the priorities solely based on least cost dispatching. In fact, such an approach might even save money in some cases. For example, I understand that there is one midwestern utility that is able to buy low sulfur Wyoming coal today for less than high sulfur Illinois coal.

What would you and the panel think of an acid rain control program which relied exclusively, at least in the short term, on one or more of these alternatives?

Could each of your agencies provide us with an estimate of the reductions in emissions of sulfur dioxide and oxides of nitrogen which could be achieved by requiring every power plant to switch to low sulfur coal or natural gas, and if you want to do that in writing, that would be agreeable to me, or respond here.

[A response from DOE follows:]

Argonne National Laboratory has provided us with emission reduction estimates of the two scenarios, based on extremely simplified assumptions which fail to account for many real world factors such as fuel transportation congestion or availability, and capital costs of converting existing powerplant boilers to a different fuel. In the scenario of requiring that all coal powerplants burn natural gas, the sulfur dioxide reduction would be over 15 million tons per year, and the nitrogen oxide reduction almost 3 million tons per year. Concurrent conversion of oil units to natural gas would increase the annual sulfur oxide reduction by 0.7 million tons and slightly decrease the nitrogen oxide reduction. Fuel premiums for natural gas alone would cost well over 11 billion dollars a year, based on the 1986 price of natural gas, which was lower than historical averages.

Mandatory use of low sulfur coal in existing coal plants could reduce annual sulfur dioxide emission by 9 million tons with no appreciable change in nitrogen oxide emission. Low sulfur coal fuel premiums, at a static level which does not account for the price increase due to increased demand, and the cost of upgrading particulate removal equipment, would cost almost 7 billion dollars a year.

Senator STAFFORD. Finally, obviously, there could be some serious economic dislocations if the Congress were to enact an acid rain program which were based solely on clean fuel, but the technologies described here this morning seem to focus very heavily on, to use the DOE term, Greenfield applications.

Surely there is something in-between. Last week, a panel of industry witnesses told us that there were some very promising pollution control technologies available today.

Is there any reason that Congress cannot expect these technologies, like fluidized bed combustion, LIMB, selective catalytic reduction, wet and dry scrubbing, and so on, to be currently available? Will it really be the turn of the century before these technologies are available commercially?

Mr. POTTER. Senator, perhaps I can respond. I think we have to look at those technologies individually, and review them as we learn more about them.

I think that it is clear, from my point of view, we are not here to defend the management of the Clean Coal Technology program, that is DOE's job. But we strongly support the role of Clean Coal Technology in future emission reductions. We feel very strongly about that, Senator, because the benefits that come from that may be substantial.

I think the debate about control is a broader public policy debate, and we are having that debate in the Administration, as well as here on the Hill, as you know. I think that it is important to recognize the differences between those two issues as we talk through this.

Mr. WAMPLER. First, Senator, as I have discussed before, LIMB, we are predicting to be available in the next one to two years, the gasifier combined cycle, by 1992 to 1993, and some of the other ones by the mid-1990s. Some acceleration in that is certainly possible, but I would say that a conservative estimate would be somewhat sooner than the turn of the century.

Senator STAFFORD. Thank you.

Thank you, Mr. Chairman.

Senator MITCHELL. Senator Graham.

Senator **Graham**. Thank you, Mr. Chairman.

I sense that there is some disagreement, or lack of consensus within the agencies responsible to the President as to how to achieve our goals. Is there a consensus as to what our ultimate destination should be, for instance, expressed in quantified terms of SO_2 emission?

Are there Administration goals to be accomplished by 1995, or the year 2000?

Mr. **Potter**. I will take a crack at that. I think the goals that we have, at least from my point of view, within EPA, Senator, are laid out in the Clean Air Act. I think that we are meeting those goals as best we can balanced against the other priorities that we have to deal with.

There is an important point to realize here, and that is that we have different management mandates in these agencies. There is, to some extent, tension, sometimes creative and sometimes not so helpful built into the process as a result, and we have to work through that.

Senator **Graham**. Mr. Hawkins stated, and I think you concurred, that the effect of the current Clean Air Act is not a reduction of SO_2 emissions, but a substantial increase of both sulfuric and nitrate emissions between now and the year 2000. Does the Administration consider that to be an acceptable national goal?

Mr. **Potter**. I think that we all have to consider whether that is acceptable, and I think the point that he is really making is that growth factors were perhaps not adequately factored in the beginning, and that is an issue that we all need to be concerned about, economic growth.

Senator **Graham**. We had a lot of discussion last week about management styles. My own management style is one of attempting to set a quantified goal, and then determining what are the strategies necessary to accomplish that goal.

My question of EPA and DOE is, is there a quantified goal, with a chronology for sulfur and nitrate emissions by the Administration to which the various agencies that have responsibility for the attainment are expected to develop strategies for implementation?

Mr. **Potter**. Senator, I think the question of goals for emission reductions, when you talk about SO_2 and NO_X, is the central issue that we are dealing with when we deal with the science, and that is where the uncertainty lies.

Senator **Graham**. Is the answer to the question no?

Mr. **Potter**. I don't think that we have a specific time point.

Senator **Graham**. Let me ask the Department of Energy, is the answer to the question no?

Ms. **Walker**. I think the answer is that we agree with EPA that we do not have an answer. I think the Envoys recognized that. In fact, what the Envoys said was, as I pointed out earlier, that we are committed to act once we know that the action will achieve the results, and that the results are worth the cost.

They recognized the uncertainties, and that is one of the reasons that they asked for the scientific research to be focused on this still unanswered question. They recognized, the two countries recognized, that there were still some questions that were not answered.

It is difficult to set goals, or to set specific controls when you don't know what they are.

Senator **Graham**. In 1961, President Kennedy set a goal that this Nation, within the decade, would place an American on the moon and return that American safely to earth. If the President had asked the scientific community in 1961, do we know exactly how we are going to accomplish that, we would never have started the process.

It seems to me that what setting a quantifiable and chronologically dated objective does is drive the processes necessary to achieve that goal.

Are you suggesting that maybe the Congress ought to set those destinations if the Executive is unable or unwilling to do so?

Mr. **Potter**. Senator, Congress has established goals in the Clean Air Act. What we are doing with regard to the science is outside of the context of and we have worked with this committee since about 1980 as the science has developed.

I think that it is important to realize that we have come a long way. The aquatics information that we have gained in the last couple of years has been very significant. Terrestrial effects is less certain. We have developed modeling techniques for dry deposition modeling, and other activities are underway, which I think staff is well aware of, that have brought us very far in understanding this problem.

I expect that we will have the tools to set those goals, but for the time being, Congress has established in the law the goals, and we have largely achieved those goals.

Senator **Graham**. You are saying, since you concurred with Mr. Hawkins' statistics, that the goal which Congress has set is a doubling of nitrate emissions and approximately a 20 to 30 percent increase sulfate emissions between 1980 and the year 2000, and if we do nothing, we, essentially, are ratifying those previous judgments?

Mr. **Potter**. I think that it is a mistake to just take those numbers on their face. I think that we really need to understand how those trends are developed, and the inputs that go into determining where we come out over those periods of time. There are wide disagreements on those trendlines, and we are constantly examining and reexamining where we think we are going to go.

I think that it all has to be done in the context of the other commitments that we have, particularly from my point of view, to air pollution in general. When we are dealing with criteria pollutants in many cases when we are not achieving the standards. In this case, SO_2, we are achieving the standard for the most part. Those areas where we are not achieving it, we do manage and deal with, and are concerned about.

Senator **Graham**. Thank you.

Senator **Mitchell**. Thank you, Senator.

Senator Durenberger.

Senator **Durenberger**. Mr. Chairman, as I look at the two subjects of this morning's hearing, the DOE Clean Coal Technologies program, and the Report of the Special Envoys on Acid Rain, I would like to articulate, for just a minute, a dilemma that I think those of us in the Legislative Branch have.

Let me begin with the Envoys' report. I just discovered that we are approaching the anniversary of the President's promise to the Canadian Government of that five year/$5 billion American program. I discovered it because I, and your friends Mr. Chairman, are gathered down in the Finance Committee while you are busy up here, and we are debating a resolution on Canadian corn.

Senator MITCHELL. Do I still have time to make that meeting?

Senator DURENBERGER. No, we postponed it until next Wednesday.

Apropos of this issue, we are going to debate the Canadian trade situation all over again, and Pat Moynihan reminded us that we couldn't meet next Tuesday to do this because it is St. Patrick's Day and that is the anniversary of the President's promise to Prime Minister Mulroney that he would save his government. So we are going to get together, and you will have a chance to help me with my corn resolution on Wednesday, next week.

The Envoys' report has some definite criteria in it. It has retrofit, high sulfur applicability, modest near-term transboundary reductions, all of which are to be applied to this technology development program. It is clear that we have made a commitment, and it is natural for us to expect our government to live up to that commitment.

When we ask the Administration what steps they have taken to fulfill the President's promise, they point to the Clean Coal program. I guess during the course of the morning, everyone here got an opportunity to determine whether or not we have lived up to that commitment, or we haven't lived up to it. It seems to me that we probably haven't, at least not to the literal interpretation of the President's promise.

As I understand it, only three of the projects selected so far meet the Envoys' criteria. The total cost of those projects is $52 million, which is one percent of the $5 billion goal. The total SO_2 reductions from all nine projects is only 65,000 tons, or half of one percent of the emissions reductions.

The temptation here is to spend some time bashing the Administration, but I thought for a moment we ought to suppose that the Administration was here to tell the Congress that it wanted a congressional authorization for a completely new $5 billion/5 year Federal program that would, in every respect, fit the Envoys' report criteria.

If, in fact, the Administration had sent us a bill with that kind of a program in it, I ask myself the question, would the Congress support it? I think I answer that question by saying, no.

We would say that it is not necessary to wait five more years to demonstrate cost effective means to reduce acid rain. We would say that those technologies are available right now. We don't need to delay a control program any longer, because the reality is that we have been in an acid rain cul-de-sac around here for the last 7 years. We call it an acid rain precipitation assessment program, and it is the best doggone excuse for doing nothing about a problem that anybody ever invented.

It seems to me that we don't need to have another excuse to head up another blind alley called the Clean Coal Technology program, and that is the dilemma. The President promised the Canadians $5 billion in acid rain controls. We want to keep our commitment to the Canadians. They have the same view of the acid rain problem that prevails on this committee.

We are tempted to beat up on the Administration, but we dare not win that argument because we don't need to spend 5 more years proving up the technology as the Envoys have recommended, and we can't afford to give anybody any more excuses for delay. That is our quandary.

I have a way of resolving the problem, I think you are aware of it, it is my Public Works response. We treat this problem just like we treat highways and Superfund. We impose a substantial tax on emissions, and we use the revenue to purchase control technology. I think my colleagues know that I will be introducing that kind of a bill again in the near future.

What we can't afford to do, it seems to me, is agree on the notion, which is at the heart of the Envoys' report, and that is the problem or the dilemma of the 5-year wait for more cost effective control technology.

Let me pose just one question, if I might, Mr. Chairman, to the appropriate people on the panel.

If the Congress passed a bill authorizing $2.5 billion of Federal expenditures to be matched, let's say, by the private sector dollar for dollar over the next 5 years, to install retrofit technologies that meet the criteria of the Envoys' report—if we pass that kind of a bill, $5 billion total—would you recommend that the President sign that bill?

Ms. **Walker**. If I understood your question correctly, it would call for a subsidy program that in concept we would oppose. If you are talking about additional funding for expanding the menu of control options, as the Envoys' recommended, I think that that kind of a thing is under review as a result of the Vice President's commitment to take a fresh look at the Envoys' Report.

Senator **Durenberger**. Any other comments from any of you?

Mr. **Potter**. There is one point that I want to make clear from the point of view of EPA, Senator Durenberger. We have never identified the availability or lack of availability of technology as a reason for delaying action on this issue. When we have talked to the issue, it has always been discussed in terms of public policy debate itself.

We recognize that the capability is there now to deal with the problem, that is not the issue, when you talk about the broader question, and that was what my point was earlier in terms of the need to separate technology from the broader debate.

Senator **Durenberger**. The DOE position is that if we authorized $2.5 billion in public monies for retrofit technology to be matched by the private sector, DOE would not recommend that the President sign that bill.

Mr. **Potter**. I would certainly agree with the notion that we would not want to support the idea of subsidizing pollution control. The polluter pay concept is an important concept, and I think that it definitely needs to be considered in any kind of approach that you might take. Certainly the notion that there is any kind of a subsidy here would have very heavy overlying implications, and it would need to be discussed carefully.

Ms. **Walker**. Senator, as you phrased your question the second time, it did not preclude it from being a demonstration program, and my answer might be different, as I indicated, as a result that the Administration's consideration of this option has been ongoing.

As you phrased your question the first time, I took it to be a subsidy program and as Mr. Potter indicated, we would oppose that.

Senator **Durenberger**. Thank you, Mr. Chairman.

Senator **Mitchell**. Senator Baucus.

Senator **Baucus**. Thank you, Mr. Chairman.

I would like to ask the DOE why there isn't more long-term coal technology research, technologies like MHD, for example, which is near- to medium-term technology? Would the appropriate person please respond?

Mr. **Wampler**. We feel that we have a balanced program for long-term R&D. I will get you some numbers on what we are looking at in answer to your question.

[DOE supplied the following:]

Long-Term Coal Technology Research

The FY 1988 Presidential Request for Fossil Energy is $161.9 million. Of this amount, $109.4 million is for basic fundamental research related to coal.

The FY 1988 research program provides for a continuing federal role in support of longer-term, high risk research and development that will be conducted by universities, National Labs and the Energy Technology Centers, as well as the private sector. A major thrust will be on acid rain-related technologies, with substantial activities in Control Technology and Coal Preparation ($33M), and in Combustion Systems ($21.6M). Generic crosscutting research will also be emphasized, particularly in the Advanced Research and Technology Development program ($26M), Advanced Liquefaction ($2.9M) and Advanced Gasification ($0.6M).

Senator **Baucus**. This really gets to DOE's own statement that most existing plants are going to stay in existence for up to 50 years, or at least it takes a very long time for plants to be replaced. My thought is, if that is the case, we should spend more time on technologies that are going to phase in at about the time that those plants are going to be replaced.

Mr. **Wampler**. We are spending a great deal of money, when you consider that 7 out of every 10 dollars, as I recall, of the Fossil Energy R&D budget is geared toward clean coal.

Senator **Baucus**. I am sorry.

Mr. **Wampler**. Seven out of 10 dollars of our normal research budget dollars, separating those from the clean coal, are now geared toward clean coal technology, and that is long term, high risk research.

Senator **Baucus**. How much of the clean coal is long-term? It is my understanding that the long-term R&D in the President's budget has been cut 40 percent.

Mr. **Wampler**. That is true, but the reason for that is twofold. One is the elimination of phosphoric acid fuel cells, which is a technology that we feel is sufficiently mature to stand on its own, and that the private sector will commercialize and MHD, our position on MHD has been fairly consistent that it is too costly.

Senator **Baucus**. Fourteen other countries have research on MHD.

Mr. **Wampler**. Yes, Senator, I am aware of that.

Senator **Baucus**. Why doesn't the United States? Are fourteen countries all wrong?

Mr. **Wampler**. It is probably not that the fourteen countries are wrong, it is a matter of establishing priorities.

Senator **Baucus**. Maybe they have the right priorities. Maybe they are thinking long-term. My problem is that there is too much short-term thinking here. These are long-term problems. That is one of America's problems. We, in America, tend to think too much short-term.

I think that the DOE should provide some leadership, frankly, and think longer-term and look at longer-term technologies, because that is the only way, long-term, that we are more likely to come up with some solutions. I don't understand why you are cutting long-term R&D by 40 percent. I heard some words, but I didn't hear any reason.

Mr. **Wampler**. The long-term cut is primarily because of those two projects, one maturing, and one project that we consider to be too costly, given the options of some other projects that we consider to have promise.

Let me certainly say, for the record, that we intend to maintain a strong long-term high-risk R&D program.

Senator **Baucus**. With the 40 percent cut.

Mr. **Wampler**. In view of the fiscal constraints we certainly have to recognize those, yes.

Senator **Baucus**. Mr. Chairman, I won't pursue this much further, but I just think that it is very short-sighted. In fact, it is irresponsible. I think that any R&D effort that cuts long-term R&D by 40 percent is a policy that the Administration should be ashamed of.

Senator **Mitchell**. Thank you very much, Senator Baucus.

I would like to now get into the Envoys' report and the criteria. Do you have a copy of that right there, Ms. Walker?

Ms. **Walker**. Yes, I do.

Senator **Mitchell**. Would you look at page 29, the criteria begin to be identified in the next to the last line. The first one is:

> The Federal Government should co-fund projects that have the potential for the largest emission reductions measured as a percentage of SO_2 or NO_X removed.

That is the first criterion. I just read the sentence from the report.

My first point is, since we don't have the emissions data, there is no way that anyone can evaluate whether or not a project meets this criterion.

Ms. **Walker**. I would like Allen Wampler to address that, if I might, based on the projections they have made in analyzing the projects.

Senator **Mitchell**. First, there is no dispute that this is a criterion listed in the Envoys' report, is there?

Ms. **Walker**. Yes, that is a criterion.

Senator **Mitchell**. There is no dispute.

Second, do you dispute that anyone can evaluate whether the project meets this criterion in the absence of information regarding emission reductions?

Mr. **Wampler**. Senator, if you look at Figure 12 of the "America's Commitment to Clean Coal," report we have taken all of the technologies, and we have listed their environmental performance in comparison to conventional coal-fired powerplants.

You see, we are listing specifically, with a range, potential or projected SO_2 reduction, and predicted NO_X reduction also. The third column gives weight characteristics that sometimes cause additional problems. So you are looking at an assessment that actually has numbers attached to it of the potential of these technologies. So we know the potential of these technologies.

Senator **Mitchell**. Is this your conclusion, or is this merely information derived from the application submitted by the applicant?

Mr. **Wampler**. No, this is our information. This is our conclusion. This is not based on their submission.

Senator **Mitchell**. Do we have this type of information for the specific projects?

Mr. **Wampler**. Yes, we do.

Senator **Mitchell**. Has that been made available, or will it be made available?

Mr. **Wampler**. It will be made available.

Senator **Mitchell**. It hasn't been made available, but it will be.

Mr. **Wampler**. It will be made available upon your request.

Senator **Mitchell**. You see, that is the kind of thing that you need.

Mr. Hawkins, do you want to comment on this?

I have not asked you many questions, but any time that you want to comment, go right ahead.

Mr. **Hawkins**. I am gratified to learn that the Department will supply relevant emission information to the subcommittee when it is requested.

I still feel that the public is entitled to that information under the Freedom of Information Act, and we have been attempting to get that information from the Department since last May, and we have been refused four times, including a refusal to provide the Department's own independent environmental assessment on the grounds that it was part of their deliberative process.

Mr. **Wampler**. Mr. Chairman, let me make a point that might satisfy this. After all nine projects are negotiated, we intend to make the site specific NEPA documents available to the public. That information will be made available to the public.

Senator **Mitchell**. Let's go back to this report. The second criterion, Ms. Walker, is contained in the next sentence, and it is "Among projects with similar potential"—presumably that refers back to potential emission reductions in the preceding sentence—"government funding should go to those that reduce emissions at the cheapest cost per ton."

You don't disagree with that as the second criterion, do you?

Ms. **Walker**. No, I don't.

Senator **Mitchell**. The next sentence contains the third criterion:

> More consideration should be given to projects that demonstrate retrofit technologies applicable to the largest number of existing sources.

Do you agree that that is a criterion?

Ms. **Walker**. Yes.

Senator **Mitchell**. Then the last part of that sentence contains the fourth criterion, "especially existing sources that, because of their size and location, contribute to transboundary air pollution."

Ms. **Walker**. That is still part of the third criterion. It is indicating, in short, that the primary purpose of this research program—I think that it is important to remember this because sometimes people forget—is to demonstrate the kind of technology that would be needed for our future acid rain control problems—then it goes on about near term reductions.

The fourth criterion begins in the second paragraph, "Furthermore, special consideration should be given to technologies that can be applied to facilities currently dependent on the use of high-sulfur coal."

Senator **Mitchell**. Very good. Thank you.

I guess what bothers me, Mr. Wampler, is that it is no mystery that the Canadians' concern is transboundary pollution. I don't see how you can argue that any of the money spent on Phase I should apply to the Envoys' recommendations when no significant transboundary reductions will result from the projects selected.

Mr. **Wampler**. As I interpret the Report, transboundary pollution certainly is a concern, but it is not one of the primary purposes of the concerns of the report. I think that the development of the technologies for future use is a more important part of that Report. Based on that, an additional criterion, we feel that some of the money that has been spent, the Round I projects, even though those went out prior to the Report, still apply. This is simply our reasoning.

We are not trying to do a shell game with numbers. It is simply our reasoning. We think that insofar as those apply, they should be noted.

Senator **Mitchell**. The reality is, as I stated before, the President went up there. Mulroney said: Look, I have a political problem here. We are hurting. We have a lot of Canadians who are concerned about acid rain. You have to give us something. The State Department said: We have got to take care of Canada, because they are good friends. The Envoys' report is endorsed.

They come back to Washington, and the Director of OMB says: We can't spend all that money, we don't have that kind of money here, especially for something like dealing with pollution which, as the President himself has said, comes from trees.

They tried to figure out a way to meet that requirement. Now here is the Clean Coal program that has a different purpose, initiated before the Envoys' report was ever written, and is pre-existing. Money has been spent on it.

You now have the difficult task which, I have to say to you, you have discharged admirably, of trying to stretch that Clean Coal to cover this Envoys' report, when it really doesn't. The test of a good lawyer, Mr. Wampler, is the guy who can argue a lousy case. Anybody can argue a good case. You have discharged that admirably.

It was not intended for that purpose. That is not what the Clean Coal program was intended for. You have manufactured this rationale. I think you are, in Phase II, going into it to try to move in that direction.

The Canadians are in a tough spot. They have their constituents who know what is going on and aren't happy, but they can't be too offensive in dealing with the Administration because they are friendly. So they have to tread a fine line between making the case to the President, and also making the case to the Canadian people.

My time is up on this round.

Senator Graham.

Senator GRAHAM. I have no further questions, Mr. Chairman.

Senator MITCHELL. Senator Baucus.

Senator BAUCUS. I would like to ask EPA what the status is of their study of the health assessment review of sulfur dioxide standards.

Mr. POTTER. We received our closure letter, Senator Baucus, from CASAC on the SO_2 standard.

Senator BAUCUS. Who is CASAC?

Mr. POTTER. It is the Scientific Advisory Board, the Clean Air Scientific Advisory Committee of the Scientific Advisory Board, and they do the peer review of the information that is being used as the basis for making the SO_2 standard decision.

We have received a closure letter from them. We are in the process of considering what they have said to us. We have sessions with the Administrator, and we are basically on track to get very much into the SO_2 issue later in this year.

The same people that do this, I would make this point, are the ones who are involved in setting the particulate standard within the Office of Air Quality Planning and Standards. So we have a duplication problem, but we are essentially on track with SO_2.

Senator BAUCUS. When do you expect that review to be completed?

Mr. POTTER. I think that we are probably going to be talking in terms of a May or June time frame for a decision on SO_2.

Senator BAUCUS. Will you wait for the Clean Coal program to be completed before you complete your review?

Mr. POTTER. This is totally independent of the Clean Coal technology action.

Senator BAUCUS. So you will not wait.

Mr. POTTER. No.

Senator BAUCUS. Thank you.

Thank you, Mr. Chairman.

Senator MITCHELL. Thank you, Senator.

Mr. Potter, I just want to ask you one more question. I thought that Senator Graham's line of questioning was excellent in discussing the need for some specific objective, and then a strategy to pursue it.

In response to his question regarding the trendlines on emissions, you said "there are wide disagreements on those trendlines." Mr. Hawkins made a statement regarding anticipated emissions, and you concurred in it.

The DOE has already received a report, May, 1985, "An Economic Assessment of Long-Term Emission Reduction Alternatives," which I assume you accept, Mr. Wampler. This is a report prepared for DOE by ICS, Incorporated.

Mr. Wampler, I don't know whether you accept or reject the report, but according to this report, SO_2 emissions increase between now and the year 2000, decrease slightly and don't go down substantially until the year 2030, 50 years from now, two generations of Americans away.

My question to you, Mr. Potter, where is the wide disagreement?

Mr. Hawkins, you and DOE, at least the DOE study, don't express any disagreement.

Mr. POTTER. Senator, maybe I overstated the disagreement. I think the point is, and I think we are probably closer to Mr. Hawkins on the trendline, perhaps, than others, for instance, DOE, or others.

My point is that there is a tendency for there to be wide disagreement on these issues when you are talking about trendlines that go out into the future 20, 30, 40 years, and that is an important thing to realize when we are talking about trendlines like that.

The information that we are dealing with now in terms of trends is indicating that emissions are, indeed, coming down. In fact, they are still coming down based on 1985 data that we are looking at and that we use as the basis for our actual statement about what we have done to achieve the standards of the Clean Air Act.

For the future, we have to consider carefully the inputs, and there are people, other than those of us here in this room who have had comment on these trends and on the inputs, and it is a complicated business. This is really my only point.

Senator MITCHELL. Ms. Walker, would you like to comment on that?

Ms. WALKER. The only thing I would add is that the ICF report is perhaps one of the more conservative of the analyses we have done. We also have others, and we will supply those for the record, as we indicated.

I am not sure that it would be a clear statement of the DOE position regarding trends based on assumptions it has made, to say what you have said from that analysis. I think the most concerted view at this point, by our agency, would be that SO_2 emissions will remain approximately the same or decline slightly through the year 2010. We will be happy to supply the details of that.

Senator MITCHELL. There is a report done at your request, which shows an increase.

What evidence is there to support the statement you have just made that there will be a decline?

Ms. WALKER. We have an additional analysis done by Argonne for us, and we have other analyses. As I indicated, we will provide those for you. This is perhaps the most conservative of the ones done for us. Taken all together, in reviewing the assumptions on which they are based, our view is somewhat different than that expressed in the single report from which you are quoting.

Senator MITCHELL. All right. Would you submit all of the evidence upon which your position is based, together with the conclusory statement of your present position, and the reasons for it to the committee?

Ms. WALKER. Yes, we will.

Senator MITCHELL. That will be very helpful.

[DOE supplied the following:]

The information requested may be found in the report "Environmental Trends Associated with the Fifth National Energy Policy Plan", provided as an insert for page 251, supra.

Senator MITCHELL. Mr. Hawkins.

Mr. HAWKINS. Just one comment, Mr. Chairman.

There is a problem of self-fulfilling prophecy in some of these projections. Part of the range of estimates is due to the assumption of when existing plants retire, how old they must be before they retire.

The self-fulfilling prophecy aspect of this has a lot to do with what level of pollution control you apply to them, because existing plants will retire only when it becomes more expensive to continue to operate them than to retire them and replace them with alternative types of demand meeting potential.

Emission control requirements, if they are kept at their current grandfathered status under the Clean Air Act, from new source performance levels, they will continue to operate those plants longer.

If you take the Administration's position to not change the Clean Air Act, you get the result that they disagree with, that is, that the plants will continue to operate longer. If you take the position that they disagree with on the Clean Air Act, that is control these plants, then you will get the results which they are going to claim happens in the absence of change in the law. They have a consistency problem in their projections.

Senator MITCHELL. They have a 'heads, they win; tails, you lose' approach to the problem. They are taking the best of each side of the argument is what you are saying.

Mr. HAWKINS. They are ignoring the market forces that are reduced by having differential control requirements. As long as these plants continue to be grandfathered, they will continue to operate past their book life.

This is quite a remarkable phenomenon. When the Clean Air Act was passed in 1970, Mr. Chairman, the Federal Power Commission had done a survey saying that plant life estimates were going to be 30 to 35 years.

The new source performance standards were enacted into the law in 1970 with the assumption that there would be that kind of turnover, and that the new source performance standards would provide an engine for gradual reductions in national pollution levels over the remainder of this century.

The utilities signed 20-year contracts for coal. When a coal mine is opened up, the assumption is that they are going to get 20 years of production out of it, maybe 30 years. They set their rates based on 30-year lifetimes, and they charge it against their consumers based on that phenomenon. What is now happening is that a windfall is being enjoyed. It is not only a cash windfall in terms of extending the life of these plants, but it is a negative pollution windfall to the rest of us, because they will continue to operate in a grandfathered manner.

If I might just take one more moment. Closer to home, we have a remarkable event, which there is going to be a hearing before the Maryland Public Service Commission later this week.

PEPCO, the local utility, instead of building a new plant, is going to purchase the equivalent of a 450-megawatt powerplant from Ohio Edison. They are going to wire the electricity over from Ohio Edison's service territory in a contract that will extend out to the year 2005.

By doing it that way, they are getting grandfathered energy, which has pollution levels associated with three or four times what would happen if PEPCO built a new power plant. But because Ohio Edison has a lot of slack capacity, they will sell this power to PEPCO, and produce power at four times the pollution level through the year 2005 through the increased operation of these grandfathered powerplants.

It is a bad situation that the current law isn't dealing with.

Senator BAUCUS. Is the Clean Coal Technology program considering the problems associated with global warming?

Ms. WALKER. I believe, Senator, that DOE's involvement in that particular scientific phenomenon is being carried out by the Office of Energy Research under Dr. Trivelpiece. We may be able to supply information for you, for the record, but the particular programs represented here today do not have an involvement directly in that issue.

Senator BAUCUS. Mr. Wampler, is that correct?

Mr. WAMPLER. Yes.

Senator BAUCUS. Fossil energy does not know to what degree DOE is looking at to what degree Clean Coal Technology is addressing global warming. If you don't know, you must not be doing it.

Mr. WAMPLER. Let me let Jack Siegel answer that, he may have some information on that.

Mr. SIEGEL. Thank you, Senator.

In fact, we are following very closely the work that is going on, led by the Department of Energy; it is an international activity on CO_2 warming.

As Ms. Walker mentioned, the lead responsibility within the Department of Energy is in the Office of Energy Research.

Senator BAUCUS. You answer is that no Clean Coal Technology research itself is dedicated to the problems associated with global warming?

Mr. SIEGEL. That is right. We are conducting some studies in conjunction with the work that our Office of Energy Research is doing to look at where we might want to focus research in coal technology in order to do something about reducing the levels of CO_2, but we are not currently doing anything.

Senator BAUCUS. Have you given any thought to directing some Clean Coal technology to the problems associated with global warming? Have you considered it? Have you discussed it?

Mr. BAUER. With respect to the first Clean Coal solicitation, we were pretty much guided bylaw as to what the focus of that should be. We really have not discussed whether or not we should consider in the next Clean Coal solicitation technologies that would reduce CO_2. But we are currently discussing the focus of that program, and we certainly will consider that.

I should point out that most of the technologies that we are developing under the Clean Coal program are more efficient than the coal technologies that they would be replacing, and as a result would emit less CO_2 per pound of energy produced.

Senator **Baucus**. Thank you.

Senator **Mitchell**. Senator Graham, do you have anything further?

Senator **Graham**. No, thank you, Mr. Chairman, I have no further questions.

Senator **Mitchell**. Before we conclude, I want to give any witness the opportunity to make any comment they would like, if there is anything I have said to which you feel a response is appropriate, I would welcome it. I want to give you the last word, if anyone would like it.

[No response.]

Senator **Mitchell**. If not, thank you all very much. You have all been very informative. We look forward to working with you in the future.

The hearing is adjourned.

[Whereupon, at 11:50 a.m., the subcommittee adjourned.]

[Statements and other material supplied for the record follow:]

THE NATIONAL CLEAN COAL TECHNOLOGY PROGRAM

Testimony by
J. ALLEN WAMPLER
Assistant Secretary for Fossil Energy
U.S. Department of Energy

before the

Subcommittee on Environmental Pollution
Committee on Environment and Public Works
U.S. Senate

March 11, 1987

Mr. Chairman and Members of the Committee:

The term "clean coal technology" has become an increasingly important part of our energy vocabulary. It has come to signify a new generation of highly efficient, environmentally clean coal-based technologies -- concepts that will permit this nation to increase its use of coal while continuing the excellent progress made in the last decade to improve the quality of our air.

I am pleased to have the opportunity today to describe these emerging new technologies. My testimony this morning will focus on both the ongoing Department of Energy Clean Coal Technology program as well as the very substantial efforts underway outside the federal initiative. It will also describe the environmental and performance benefits of these new coal-based technologies -- benefits that were only projected a decade or so ago but which today are being demonstrated through actual, commercial-scale, functioning hardware.

Perhaps most importantly, Mr. Chairman, I hope my testimony will provide reasonable justification for why the Department of Energy believes the development and deployment of advanced clean coal technologies represents a preferred course of national response to such issues as acid rain as well as the future energy security of our nation.

To place the new slate of emerging clean coal technologies into proper context, it is important to recognize the limitations of the current environmental control options available to industry.

Today's Choices -- Both Limited and Costly

Most conventional pre-New Source Performance Standards (NSPS) coal-fired power plants in the U.S. are equipped with only particulate removal devices. Sulfur emissions are directly linked to the sulfur content of the coal feed. A typical power plant in this category is about 35 to 38 percent efficient in producing electricity from raw coal feed.

A coal-fired plant built since the NSPS requirements were imposed in 1978 is typically less efficient, due to the need to install flue gas scrubbers. These scrubbers -- typically large, complex chemical treatment facilities -- use 5 to 10 percent of the plant's electricity.

The capital cost for a new plant in the 350-1000 megawatt size range is about $1500-$1800 per kilowatt, roughly 20 percent of which is associated with required environmental controls including a flue gas scrubber. With routine maintenance, a coal-fired power plant is expected to perform at design specifications for about 30 years. Conventional power plants are generally very sensitive to coal feed due to varying boiler types and the design of coal and ash handling equipment.

Until the recent emergence of the first of the new suite of clean coal technologies, utilities could achieve additional sulfur dioxide (SO_2) emission reductions by one of only three options: coal cleaning, retrofit flue gas scrubbing, or coal switching. Actually reducing SO_2 emissions using any of these conventional controls, however, would pose severe problems due to their inherent limitations. For example:

Coal Cleaning -- Conventional techniques for cleaning coal have a limited ability to remove sulfur. Sulfur occurs in coal principally in two forms:

Pyritic sulfur is combined with iron and occurs as distinct, finely dispersed, often microscopic particles. In typical U.S. coals, pyritic sulfur can make up from 30 percent to 70 percent of the coal's total sulfur content.

Organic sulfur is bound chemically to the carbon atoms of coal. It, too, can comprise 30 percent to 70 percent of the total sulfur in coal.

Conventional coal cleaning removes only pyritic sulfur. Moreover, state-of-the-art physical cleaning technologies, which usually rely on specific gravity differences to separate impurities from coal, are capable of removing only 20 to 50 percent of the pyritic sulfur -- or approximately 10 percent to 30 percent of the total sulfur content. They are ineffective in removing any of the organic sulfur.

Flue Gas Scrubbing -- Flue gas scrubbing, applied to new power plants, can reduce SO_2 emissions by 90 percent. The U.S. electric utility industry operates more than 140 scrubbers and more than 70 additional units are under construction or planned.

Continued application of flue gas scrubbers on new power plants could keep nationwide SO_2 emissions from rising abruptly but will not reduce overall emissions until existing, pre-NSPS emitters are retired. A single scrubber for a typical new 500-megawatt coal burning plant may require an initial investment of $100 million or more, and capital costs for adding scrubbers on older plants -- if sufficient site space is available to make that possible -- can equal or exceed the original plant investment.

Also, since conventional scrubbers consume a portion of the electrical output of a power plant, the plant's overall efficiency is reduced and the cost of electricity is increased. Their byproduct, a pasty sludge, is difficult and costly to manage, and often scrubbers are unuseable because a utility does not have the land available for sludge disposal. (During its lifetime, for example, a typical 500-megawatt power plant with a scrubber is likely to require a sludge disposal pond more than 500 acres in area and more than 40 feet deep.)

Today's flue gas scrubbers also are designed primarily as SO_2 control devices; they do not remove nitrogen oxides (NOx) very effectively.

Coal Switching -- Changing a plant's raw coal feed to a lower sulfur coal is extremely costly in terms of the premium paid to purchase and transport low sulfur coal. Because low sulfur coal is generally more expensive than high sulfur coal, utility operating costs will be increased. Switching to a different coal feed can also result in boiler derating (reducing power output) due to coal characteristics which do not meet or are in conflict with a particular boiler's design specifications.

Also, there is the incalculable cost of the social disruptions caused by shifting supply sources and displacing miners and their families.

What Is Meant by "Clean Coal Technology"?

Emerging clean coal concepts are linked by a common characteristic -- the capability to combine a consistently high degree of environmental effectiveness, economic viability and plant reliability. Most are also relatively insensitive to coal type.

The emerging slate of advanced technologies includes techniques that extract sulfur and mineral matter either before, during or after the combustion process. Other clean coal technologies depart radically from the conventional concept of coal combustion; instead, they convert coal initially to a combustible gas which can then power a combined-cycle turbine configuration. Many combine effective SO_2 control with the capability of controlling levels of NOx generated during combustion of either the coal or the synthetic gas.

Pre-combustion techniques include advanced physical coal cleaning, chemical cleaning and microbiological cleaning.

Combustion processes can include additives that extract the sulfur inside the combustor, furnace, or boiler. Some of these concepts also inject natural gas into the upper region of the furnace to create a fuel-rich zone in which NOx is converted to harmless molecular nitrogen. Several technologies involve new combustor configurations, such as the "fluidized bed" combustor, to achieve more effective combustion and mixing of the coal and sulfur sorbent. Many of these technologies also operate at temperatures low enough to impede generation of nitrogen oxides, and in some, the mineral impurities in coal are extracted as ash or a molten slag.

Post-combustion clean-up can be addressed by various approaches. These include (1) sensitizing the flue gases with electron beams to promote oxidation of SO_2 and NOx to sulfuric and nitric acids, respectively; (2) adding alkaline sorbents to the flue gases to react with SO_2 to form easily disposable wastes; and (3) passing the flue gases through a bed of alumina spheres coated with copper oxide to ultimately extract pure sulfur.

Gasification-combined cycle techniques integrate one of several types of coal gasifiers with various gas cleanup approaches followed by high-efficiency gas turbines or gas/steam turbine combinations.

Because the constituents in coal (e.g., sulfur and mineral matter) vary significantly from one coal source to another and the population of coal-fired electric powerplants in the United States is extensively heterogeneous in age, size, and configuration, it is difficult to predict which of the emerging new coal technologies may be preferable. In all likelihood, the choice will be dictated by plant- and site-specific factors, i.e., quality of coal source; location, age and size of powerplant; local, state and federal environmental restrictions; and a host of other factors.

In some cases, the choice may be a combination of pre-combustion, combustion, or post-combustion processes. For example, conditioning the raw coal by physically cleaning it can improve the effectiveness of sorbent capture of sulfur in flue gases, and in situ (i.e., during combustion) capture of sulfur reduces the need for extensive flue gas cleanup.

How Will Clean Coal Technologies be Applied?

Clean coal technologies when used alone or as part of energy systems have the potential to be used for a variety of applications.

Many of the technologies (e.g., integrated gasification combined cycle, pressurized and atmospheric fluidized-bed combustion and advanced flue gas clean-up devices) can be used on new, "grassroots" facilities, allowing them to meet and, in many cases, far exceed current utility New Source Performance Standards.

Others (e.g., advanced coal cleaning, limestone injection, gas reburning) can be introduced as "retrofits" to existing facilities, providing improved environmental performance without extensive balance-of-plant modifications.

Several of the concepts -- the integrated gasifier-combined cycle and fluidized bed technologies -- can also be applied to existing plants as part of an overall plant refurbishing or "repowering."

Each of these applications is discussed in more detail as follows:

"Grass Roots" Applications

Several of the clean coal technologies such as fluidized-bed combustion, integrated gasification combined cyle, chemical coal cleaning, and others are anticipated to be used commercially in new, "grass roots" facilities. These advanced "grass roots" technologies have significant implications from an emissions control perspective. Analyses conducted by industry and DOE show that SO_2 emissions are anticipated to decline significantly as old, poorly controlled coal-fired power plants are replaced by new plants meeting NSPS even with the large increases in projected coal use.

Clean coal technologies, once commercialized, have the potential to accelerate the decline in SO_2 emissions as a result of their ability to control SO_2 better and/or more economically than conventional technologies. Their inherent economic and performance advantages could also accelerate replacement of older plants.

Many of the clean coal technologies selected have the added advantages of improved NO_x performance and production of useable or more easily disposable wastes than conventional technologies.

The longer term strategy for SO_2 control, that of replacement of retiring plants, has several advantages over requirements which would result in the immediate installation of SO_2 controls at existing plants. These include:

- the reduction of present value utility costs by phasing emission reductions gradually over time.
- the prevention of negative regional coal production impacts by ensuring that major reductions in SO_2 emissions occur in a manner that does not require substantial coal switching.
- the ability to defray control costs by giving utilities greater flexibility in meeting emission limits imposed on individual power plants or units (e.g., trading emission rights between existing and new utility power plants) if such legislation were proposed.

Retrofit Applications

Included in this category is both pre-combustion coal cleaning and technology that can be installed at or on the existing power plant itself.

Coal cleaning is, in essence, a "fuel retrofit" that avoid the possible social disruptions of fuel switching. Advances are being made in several areas of coal cleaning:

Advanced physical coal cleaning -- techniques involving a variety of approaches such as fine grinding, "true heavy liquid" cyclones, froth flotation, and selective coalescence.

Chemical coal cleaning -- concepts that expose coal, for example, to molten chemicals such as sodium hydroxide which break the chemical bonds of the organic sulfur.

Microbial coal cleaning -- relatively new techniques that employ microbes to degrade sulfur in coal into a removable form.

Advanced physical coal cleaning technologies can potentially reduce SO_2 emissions by 65 percent, and advanced chemical and microbial processes are believed capable of achieving 90 percent or better SO_2 emission reductions, depending on the organic content of the original coal. Utilization of coal slurries prepared from coal processed by these advanced coal cleaning technologies results in the same emission reductions as the dry cleaned coal.

Several retrofit technologies have also emerged within the last few years that can be integrated at the power plant. These include:

Limestone Injection Multi-Stage Burners -- a technology that injects sulfur-absorbing limestone into the fuel-rich "reducing" zone of a pulverized coal burner.

Slagging combustors -- devices that can control or remove objectionable sulfur and particulate matter from a coal-derived fuel before it is injected into retrofitted oil or gas boilers or heaters.

Gas Reburning -- a concept that injects a secondary fuel, such as natural gas, above the primary combustion zone to create a fuel-rich region in which nitrogen oxides are converted to harmless products.

In-Duct Sorbent Injection -- a technique that injects sulfur-capturing sorbents directly into a power plant's ductwork leading from the boiler to the stack.

Advanced Flue Gas Cleanup -- a variety of innovative scrubber technologies that use chemicals such as copper oxide or electron beam irradiation to improve the effectiveness of pollutant capture.

These technologies can be installed on or used by existing facilities with fairly low capital cost modifications to control SO_2 and/or NO_x emissions to varying degrees.

Retrofit technologies generally cause some losses of efficiency (3 to 10 percent) and power output because energy is required to operate them. Post-combustion cleanup technologies, namely conventional and advanced flue gas scrubbing, have similar economic performance penalties. Flue gas scrubbing generally costs more than combustion modification processes such as limestone injection multistage burner, slagging combustors, gas reburning and sorbent injections. Pre-combustion cleanup, i.e., coal cleaning and coal slurry preparation, can result in slight efficiency increases due to less ash handling, however fuel costs are increased. In general, the advanced retrofit control technologies expand the range of coal types that can be cost-effectively controlled and are not as space or site limited as flue gas scrubbing.

Repowering Applications

Repowering technologies are also important options for pollution control of a large number of existing boilers where increased electricity output and plant life extension are also required.

> **Integrated Gasification Combined Cycle** is a power generating configuration in which coal is first converted to a combustible gas, cleaned and then used to power a gas turbine and steam turbine combination.
>
> **Atmospheric or Pressurized Fluidized Bed Combustion** is a technology in which coal is injected into a hot "bed" of sulfur-absorbing limestone or dolomite suspended inside the combustor by upward-blowing jets of air.

Some, like the Congressional Research Service in its January 21, 1987, report "Acid Rain, DOE's Clean Coal Technology Program, and the Lewis-Davis Report: Squaring a Circle?", very narrowly define the term "retrofit" to mean those technologies which would require less capital investments than conventional flue gas desulfurization units (scrubbers). We believe that such a narrow definition is not in concert with the real-world thinking of utilities that must try to minimize total electricity costs when addressing plant life-extension and potential emission reductions.

Repowering technologies often increase efficiency and boost power output. To repower an existing coal-fired plant, the existing boiler would be replaced with a new coal gasifier or pressurized fluidized bed combustor along with a gas turbine, gas cleanup system and heat recovery boiler. The remaining equipment (coal handling, steam turbine and power generation equipment) would likely be refurbished. Repowering requires significant capital investments, but the increased power output offsets most of the capital cost and provides net benefits both to the consumer and to the environment.

For example, repowering an existing coal-fired power plant with an integrated gasifier-turbine combined cycle (IGCC) configuration would require an investment of $1100 to $1300 per kilowatt. The cost of electricity, however, would only increase by 1-2 mills per kilowatt hour because the refurbished plant would be capable of generating more electric power than the original plant. And for that investment, SO_2 emissions from the repowered portion of the plant would be reduced by up to 99 percent and NO_x emissions substantially lowered. Repowering in this manner can increase the efficiency of a power plant from a nominal 35 percent to more than 40 percent and boost its power output by 50 percent to as much as 150 percent.

Repowering using pressurized fluidized bed combustion technology increases plant efficiency from a nominal 35 percent to approximately 38 percent and increases power output by up to 50 percent. Capital costs are somewhat less ($800-$1000 per kilowatt), but because the boost in power output is less than IGCC, the cost of electricity is somewhat greater -- about 4-6 mills per kilowatt hour.

Atmospheric fluidized bed combustion repowering would not change the power plant's efficiency measurably, although it would result in a 10 to 15 percent increase in power output. The initial investment cost is lower ($700 to $900 per kilowatt) but the relatively small increase in power output results in a 6-8 mill per kilowatt hour increase in the cost of electricity. For some utilities this may still be an attractive way to achieve plant life extension and near-term SO_2 and NOx reductions.

The National Clean Coal Program

The new slate of clean coal technologies has emerged from a decade of smaller-scale development by both government and industry. Many of the concepts now crossing the commercial threshold originated in the aftermath of the 1973 OPEC oil embargo. With the nation's economy shaken by the sharp rise in oil prices and sudden concern over the vulnerability of imports, the U.S. coal research program was driven principally by a goal of displacing liquid and gaseous fuels.

In the 1980s, the perception of primary R&D needs has changed. With increased attention focused on the issue of "acid rain" and the compatibility of coal with America's environmental goals, the national research program began to concentrate more on the development of technologies to control SO_2 and NOx.

Many of the technologies under development in the 1970s for other purposes also had the potential to be attractive alternatives to conventional pollution controls.

The scientific and engineering groundwork laid in the 1970s and early 1980s now forms the technological basis for developing, demonstrating and deploying the new generation of clean coal technologies. Most importantly, this technological evolution is taking place not only through federally sponsored efforts but also through initiatives pursued by state governments and by the private sector.

All of these efforts -- both public and private -- combine to make up the "National Clean Coal Program", and all should be included when discussing America's commitment to increasing the use of coal in concert with achieving a higher quality environment.

The Federal Program - Clean Coal Technology Round #1

The initial federally-conducted Clean Coal Technology effort began when Congress passed Section 321 of Pub. L. No. 98-473, the Continuing Appropriations Act for FY 1985. This provision directed the Secretary of Energy to solicit from the private sector "statements of interest in, and proposals for projects employing emerging clean coal technologies." The "Chronology of Major Events", attached to this formal statement, highlights the activities that ensued, including the May 1, 1985 Report to Congress that has since become known as the "Section 321" Report. At that time, 175 submissions were received with project values totaling over $8 billion.

On December 19, 1985, Pub. L. No. 99-190, "An Act Making Appropriations for the Department of the Interior and Related Agencies for the Fiscal Year Ending September 30, 1986, and for Other Purposes," was signed into law. This Act, among other things, provided funds to conduct cost-shared clean coal technology projects for the construction and operation of facilities that would demonstrate the feasibility of future commercial applications of such technology.

The Act further required that DOE issue a "general request for proposals" for the Clean Coal Technology Program within 60 days of the date of enactment (i.e., by February 17, 1986), provided 60 days from issuance of that request for the proposals to be submitted (i.e., by April 18, 1986), and required the selection of projects for negotiation no later than August 1, 1986. The Department met the Congressional requirements in issuing a Program Opportunity Notice soliciting proposals and receiving and evaluating the responses.

The Act made available $397.6 million for this program, as follows: $99.4 million in fiscal year 1986, $149.1 million in fiscal year 1987, and $149.1 million in fiscal year 1988.

Of these monies, $1.2 million was transferred in FY 1986 to the Small Business and Innovative Research Program (SBIR) as required by the Small Business Innovative Development Act of 1982 (Pub. L. No. 97-219) and is unavailable to the Clean Coal Technology Program. This transfer leaves currently available funding of $98.2 million for FY 1986 and total current availability for the first solicitation of $396.4 million.

In addition, $3.7 million will be transferred to the SBIR program for FY 1987 and FY 1988. Also, $25 million has been held in reserve to cover the cost of project overruns in the event that the Government agrees to share such costs. Finally, $5.5 million has been set aside for contracting, travel, and ancillary costs incurred by the DOE in implementing the Clean Coal Technology Program. The remaining $362.2 million is currently available for award to eligible clean coal projects.

By Congressional direction, the first round of competition for federal cost-sharing was open to all market applications of clean coal technology that apply to any segment of the United States coal resource base. The competition also encompassed both "new" and "retrofit" applications.

A draft Program Opportunity Notice was issued on January 30, 1986, for public comment. Comments were received from 23 entities.

The final Program Opportunity Notice was issued on February 17, 1986. In response to the public comments received regarding the draft notice, and also as a result of continued review by the Energy Department's Source Evaluation Board, several improvements were made in the final solicitation compared to the original draft. Also, an amendment to the Program Opportunity Notice was issued on February 24, 1986, which revised sections relating to revenue sharing.

A total of 760 copies of the solicitation were distributed. The "Source List" was developed from the 175 responses to the DOE request for statements of interest (see above). This list was augmented by requests received in response to the January 27th Federal Register and January 28th Commerce Business Daily notices of availability of the draft Program Opportunity Notice.

To enable prospective offerors to gain a better understanding of the Department's objectives in the Clean Coal Technology program and to receive answers in response to written questions submitted regarding the Program Opportunity Notice, a preproposal conference was held in Washington, D.C. on March 6, 1986. Approximately 280 persons attended. On March 24, 1986, a compilation of all questions and answers addressed at the conference and questions deferred for subsequent response was issued to all recipients of the solicitation and to all conference attendees. On April 9, 1986, a supplemental package of questions and answers was issued to address the inquiries received between March 24 and April 4, 1986.

The Environmental Protection Agency (EPA) was given a copy of the draft solicitation to review, and the agency provided comments to DOE. Further, EPA personnel served as advisors to DOE during evaluations; the EPA advisor provided comments on the environmental aspects of all proposals and an EPA representative served as a member of the evaluation team for proposals where the agency had expertise (those involving flue gas desulfurization and the Limestone Injection Multistage Burner technology).

After considering the evaluation criteria, program policy factors, and the National Environmental Policy Act (NEPA) strategy as stated in the solicitation, the Energy Department selected proposals from the following offerors, listed in alphabetical order, as best furthering the goals and objectives of the Program Opportunity Notice:

American Electric Power Service Corporation
Babcock & Wilcox
Coal Tech Corp.
Energy & Environmental Research Corporation
Energy International, Incorporated
General Electric Company
Ohio Ontario Clean Fuels, Incorporated
The M.W. Kellogg Company
Weirton Steel Corporation

In the event that a cooperative agreement could not be awarded to any of the selected proposers, the department identified a second list of candidate proposers:

City of Tallahassee
Colorado - UTE Electric Association, Inc.
Combustion Engineering, Inc.
Consolidation Coal Company and Foster Wheeler
  Power Systems, Inc.
McDonnell Douglas Energy Systems, Inc.
Minnesota Department of Natural Resources
Southwestern Public Service Company
Tennessee Valley Authority (2 proposals)
TRW, Inc.
United Coal Company
Western Energy Company
Westinghouse Electric Corporation
Wisconsin Electric Power Company

If, at the conclusion of negotiations with the originally selected proposers, agreements cannot be reached with any firm, the evaluation criteria and program policy factors will be applied to the second list to select additional project(s).

On August 21, 1986, a "Comprehensive Report to Congress On Proposals Received in Response to the Clean Coal Technology Program Opportunity Notice" was submitted to Congress. That report outlined the solicitation process implemented by DOE for receiving the first round of Clean Coal Technology proposals, summarized the proposals received, provided information on the technologies that were the focus of the program, and reviewed special issues and topics related to the solicitation.

Current Status -- At the end of February 1987, negotiations had been completed on two of the Clean Coal Technology projects. The American Electric Power Service Company, acting on behalf of the Ohio Power Company, and the Coal Tech Corporation had signed the proposed cooperative agreements. The Energy Department, under provisions of Pub. L. No. 99-190, has forwarded comprehensive reports for the two proposed projects to the Congress. Upon completion of the 30 (session) day review -- now estimated to be March 20 -- the Energy Department will complete the signing of the Cooperative Agreements and start its participation in these projects.

Negotiations on the remaining projects will be completed as rapidly as possible. While it is difficult to predict an actual completion date for the negotiations without compromising the government's negotiating position, our expectation is to have all of the comprehensive reports submitted to the Congress by the end of June.

Thirteen of the 14 proposers on the second list of candidate projects have kept their proposals in an active status. One of the firms, Wisconsin Electric Power Company, has withdrawn their proposal for a pressurized fluidized bed combustion project and has indicated that they will proceed with other plans for the Port Washington Power Plant.

Relationship of Clean Coal Technology Round #1 to Special Envoys Report

At the request of the Senate Energy and Natural Resources Committee, DOE issued a second report to Congress on October 24, 1986, entitled "Report to Congress on the Relationships Between Projects Selected for the Clean Coal Technology Program and the Recommendations of the Joint Report of the Special Envoys on Acid Rain."

The report pointed out that the first round of competition was initiated in direct response to guidance received from the Congress well before the Joint Report of the Special Envoys (the Lewis-Davis Report) was released. Congress required that the Clean Coal Technology Program, as envisioned at the time Pub. L. No. 99-190 was passed, demonstrate a broad spectrum of coal technologies in response to a diverse set of environmental, economic, and security goals. These criteria are set forth in the legislative history of the law authorizing funds for the Program. This history includes the following statements:

- "... that the solicitation be open to all markets utilizing the entire coal resource base."
- "Technologies that use coal cleanly and efficiently, so that needed generating capacity will be available on time, and with minimal environmental impact."
- "Technology that can be retrofitted to existing applications of coal will also provide pollution relief. Clean uses of coal in other applications will also reduce dependence on foreign oil as well as increase coal markets."
- "... other [non-utility] applications such as industrial, including steel and iron ore processing, and transportation uses are also of interest."

In January 1986, when the U.S. and Canadian Special Envoys released their joint recommendations, they identified the following goals with respect to control technologies:

- The most important goal was to expand the slate of available technologies to control SO_2 and NO_x by demonstrating less expensive technologies that could be used to control suspected acid rain precursor pollutants.
- A secondary goal was to achieve through the demonstrations some near-term U.S. emission reductions.

The Envoys recommended the following project selection criteria:

- projects which could get the greatest reductions in SO_2 and NO_x;
- among projects with similar potential, funding should go to those with maximum cost effectiveness (least cost per ton of controlled pollutant);
- projects that demonstrate retrofit technologies applicable to the largest number of existing sources especially those that because of their size and location, contribute to transboundary air pollution;
- technologies that can be applied to facilities currently dependent on the use of high sulfur coal.

Although there appear to be significant differences in the direction and focus of the two efforts, a subsequent comparison between the projects selected for the Clean Coal Technology Program under Pub. L. No. 99-190 and the criteria of the Lewis-Davis report demonstrated that while being fully responsive to the directive of the Congress, DOE did select three projects which fully met the criteria set forth in the Lewis-Davis Report and that all nine demonstration projects met at least two of the Lewis-Davis criteria. Moreover, upon their commercial application, five of the projects would meet all of the criteria.

The report concludes that many of the technologies selected under the Clean Coal Technology Program are consistent with the technologies that would have been selected if one followed the recommendations in the Lewis-Davis Report. The program also includes other technologies consistent with the broad Congressional mandates which created the program. These other technologies also should assist with the longer term reduction of suspected acid rain precursor pollutants.

The Federal Program -- Clean Coal Technology Rounds #2 and #3

The President's Fiscal Year 1988 Budget Request to Congress contains a commitment to expand the nation's Clean Coal Technology program -- adding $150 million in federal funds in fiscal years 1988 and 1989 and a total of $350 million over the next five years.

Pending Congressional approval of the President's request, the second round of Clean Coal Technology project competition would be held in fiscal 1988. A third round -- intended for technologies that were not sufficiently mature to compete in the second round -- would be held in fiscal 1990. The funding profile for the Clean Coal Technology program, therefore, would appear as follows:

	FY1986	FY1987	FY1988	FY1989	FY1990	FY1991	FY1992	
Round #1	$ 98.2	$149.1	$149.1	--	--	--	--	396.4
Round #2	--	--	50.0	100.0	--	--	--	150.0
Round #3	--	--	--	--	50.0	100.0	50.0	200.0
TOTAL	$ 98.2	149.1	199.1	100.0	50.0	100.0	50.0	746.4

The Department has proposed that projects selected in Rounds #2 and #3 focus on technologies that could retrofit, repower or modernize existing coal burning facilities, thus targeting candidate projects more closely to the Special Envoys' recommendations. The same cost-sharing requirements (non-federal financing of at least 50 percent at each stage of the design, construction and operation of each project) are expected to be included in the second and third rounds of competition.

The 2nd Informational Solicitation -- In a preparatory fashion similar to that conducted for Round #1, Congress in Pub. L. No. 99-500 (the "Department of the Interior and Related Agencies Appropriations Act for FY 1987," which was signed into law on October 18, 1986) required that the Department solicit "statements of interest in, and informational proposals for" retrofit, repowering or modernization technologies.

The Department complied with the Congressional directive by issuing a Program Announcement in the Nov. 12, 1986, issue of the Federal Register (51 FR 41060-6) and a notice in the Nov. 17, 1986, issue of the Commerce Business Daily.

A total of 139 responses were received. Additionally, some letters were received regarding various aspects of the solicitation; these were not counted as submittals. The following Table provides a summary of the submittals categorized by technology, and indicates the total dollar value of all of the projects described for each category. We should emphasize that the "statements of interest" are not firm project proposals. DOE has not evaluated them on their merits or in relation to prospective program selection criteria.

Also, in examining the total value, note that not all of the submittals provided estimates of project costs.

DISTRIBUTION OF SUBMITTALS RECEIVED BY TECHNOLOGY
(in descending order of number received)

Technology	Number Received	Total Value[2]	Percentage of Grand Total Value
Flue Gas Cleanup	49	$ 706,028,000[1]	13.7 %
Coal Preparation	25	409,003,000[1]	7.9
Fluidized Bed Combustion	15	1,072,516,000	20.8
Advanced Combustors	13	230,535,000[1]	4.5
Alternative Fuels	13	218,141,000	4.2
Surface Coal Gasification	11	1,903,200,000	36.9
Heat Engines	3	62,179,000	1.2
Industrial Processes	3	57,500,000	1.1
Other Repowering[3]	3	23,000,000[1]	0.4
Coal Liquefaction	2	71,000,000	1.4
Fuel Cells	1	6,000,000	0.1
Magnetohydrodynamics	1	400,000,000	7.8
TOTALS:	139	$ 5,159,102,000*	100.0 %

Notes:

(1) Five of the submittals did not provide project cost information, as follows: two in the Flue Gas Cleanup category, and one each in the Coal Preparation, Advanced Combustors, and Repowering categories.

(2) Values reflect total project costs as provided by the submitters, including both governmental and private sector cost-shares. The data have not been evaluated, and are reported as received.

(3) The Other Repowering category includes those submittals of repowering projects where the specific technologies that would be used have not been specified.

Another perspective can be obtained by comparing the submittals to comparable data for the previous two program solicitations. It is interesting to note how little the percentage distributions change, with the noteworthy exceptions being surface coal gasification (15% and 17% in earlier solicitations, but only 8% now), and flue gas cleanup, which, in recognition of the "retrofit, repowering, and modernization" nature of the current solicitation, has increased from 18% and 14% in the Section 321 and in the PON, respectively, to 35% in the present Program Announcement group.

COMPARISON OF THE TECHNOLOGY DISTRIBUTIONS FOR THE THREE CCT SOLICITATIONS

	S321 Prog. A.[1]		CCT PON[2]		Retro. Solic.[3]	
Technology	No. Recd.	% of Total	No. Recd.	% of Total	No. Recd.	% of Total
Advanced Combustors	10	6 %	4	8 %	13	9 %
Alternative Fuels	8	5 %	-	-	13	9 %
Coal Liquefaction	5	3 %	3	6 %	2	2 %
Coal Preparation	22	13 %	10	19 %	25	18 %
Flue Gas Cleanup	31	18 %	7	14 %	49	35 %
Fuel Cells	8	5 %	3	6 %	1	1 %
Fluidized Bed Combustion[4]	27	15 %	9	18 %	15	11 %
Gas Stream Cleanup	2	1 %	-	-	-	-
Heat Engines	13	7 %	-	-	3	2 %
Industrial Processes	-	-	3	6 %	3	2 %
Magnetohydrodynamics	2	1 %	-	-	1	1 %
Repowering[5]	-	-	-	-	3	2 %
Surface Coal Gasification	27	15 %	9	17 %	11	8 %
Underground Coal Gasification	4	2 %	1	2 %	-	-
Other	16	9 %	2	4 %	-	-
TOTALS:	175	100 %	51	100 %	139	100 %

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(1) Refers to the Nov. 27, 1984, "Section 321" Program Announcement.
(2) Refers to the Feb. 17, 1986, Clean Coal Technology Program Opportunity Notice.
(3) Refers to the Nov. 12, 1986, "Retrofit" Program Announcement
(4) Includes both Atmospheric and Pressurized Fluidized Bed Combustion, although none of the latter type was received in the latest (retrofit) solicitation.
(5) The Repowering category includes submittals of repowering projects where the specific technologies have not been specified.

The tables on the previous two pages were prepared for the Department's "Summary Report to Congress on Emerging Clean Coal Technologies Capable of Retrofitting, Repowering, or Modernizing Existing Facilities" which was forwarded to the Congress on March 6, 1987. A more detailed analysis is currently being prepared and will be provided to Congress by May 12, 1987.

The Rationale for Two Sequential Clean Coal Competitions -- The most recent informational solicitation indicated that there are enough projects capable of repowering or retrofitting existing facilities, to justify the funding level proposed for Round #2 of the Clean Coal Technology Program.

In addition, however, there are many attractive processes being pursued in earlier stages of development both within the base DOE R&D program and by R&D organizations throughout the country. Many of the concepts -- like, for example, microwave flue gas desulfurization, moving bed copper oxide flue gas scrubbing, advanced chemical cleaning, etc. -- will likely not be ready for scale up to demonstration size in time to respond to a solicitation in late 1987 or early 1988. With additional development between now and the anticipated 1990 Round #3 competition, these technologies could mature sufficiently to offer attractive options for the next generation of clean coal concepts.

The Nationwide Clean Coal Technology Program

The U.S. has made extraordinary progress in the development of a slate of clean coal technologies both in federally sponsored efforts and in the efforts financed by the private sector and by State governments.

Between 1980 and 1985, approximately $1.6 billion of a total of $3.2 billion for coal technology development was spent by both public and private research programs on advanced coal technologies with inherent reduced emissions. Now, with a major goal to improve the options available for reducing emissions from coal-fired powerplants, the Nation is on an expanded course to spend approximately $6 billion between now and 1992 to research, develop and demonstrate a broad slate of technologies which used singularly or in combination will result in more efficient and effective emission controls.

A recent DOE report, entitled "America's Clean Coal Commitment" (Feb. 1987), documents an expected expenditure of more than $6 billion between 1986 and 1992 to develop and demonstrate new clean coal technologies. Approximately $4.9 billion of the $6 billion is made up of specific clean coal projects, i.e., projects that will operate at a sufficiently large scale to demonstrate the viability of the innovative technology. The remainder of the funding is comprised of privately and publicly financed research and development efforts focused specifically on the cleaner use of U.S. coal.

Just over $2.0 billion of the national investment is represented by currently planned federal expenditures. The private sector's contribution will nearly double the federal share -- an expected $3.9 billion, of which $370 million will come from the Electric Power Research Institute (EPRI), the research arm of the utility industry.

State government funding will also make a significant contribution to the national total. While state-funded projects are underway in several States -- for example, in West Virginia, Pennsylvania, Virginia, Kentucky and several others -- Illinois and Ohio in particular have taken an aggressive role in financing large-scale development and demonstration efforts. The expected contribution from these two States alone amounts to more than $300 million.

Conclusion -- Benefits of Clean Coal Technologies

Clean coal technologies offer the potential to:

1. Control large amounts of the SO_2 and NO_x released from coal-fired power plants including those in the environmentally-sensitive Northeast.

2. Return economic benefits to American consumers by permitting clean energy to be generated without financially constraining capital investments for environmental controls.

3. Retrofit and repower aging coal-fired power plants, particularly those in the East.

4. Use high-sulfur coals, thereby avoiding the social disruptions associated with massive coal switching, and

5. Reduce acid rain related emissions -- especially from aging power plants in the nation's northeast quadrant.

Although commercial deployment is already beginning for some technologies like atmospheric fluidized-bed combustion and IGCC, how rapidly these innovative clean coal technologies will be deployed depends upon many factors. Two of the most important are (1) technology risk -- concern about the performance and reliability of the technologies; and (2) market demand -- influenced, for example, by the growth in demand for electricity and the future regulatory environment.

The $6 billion to be expended between 1986 and 1992 on clean coal technologies directly addresses the technological risk. By developing and demonstrating new technologies at commercial- or near-commercial scale, the risk of commercial deployment is reduced. Market demand, however, is much more uncertain.

Many of the emerging clean coal technologies are designed to generate electric power cleanly and more efficiently than is possible today. There is little doubt that electricity is vital to the future of the U.S. The nation's health depends on continued economic growth, and if adequate electrical generating capacity is not available, we run the risk of undermining this growth.

Coal can provide much of the resource base to ensure continued economic progress. But utilities have been understandably reluctant in recent years to invest in large, conventional baseload power plants -- either coal or nuclear fueled. The uncertainty over anticipated growth in power demand, coupled with uncertainty regarding future environmental regulations, has stalled many construction projects.

In those regions of the country where the demand for electricity is expected to increase, utility owners will soon be faced -- if they are not already -- with the need to install new generating capacity. The need for additional electricity will likely intensify as we approach the mid-1990s when the majority of existing coal-fired power plants will turn 25 or more years old. At that point, utilities must consider various options for continuing to produce power from these aging facilities or alternatively, to shut them down.

These events -- today's slowdown in construction and the anticipated future demand for new facilities, either "grassroot" plants or as replacements for older units -- have combined to create a "window" for new clean coal technologies that will open even wider in the 1990s.

For those utilities that face the dual problem of aging baseload power plants and the need for additional electricity, the repowering technologies -- integrated gasification combined cycle, pressurized and atmospheric fluidized bed combustion -- are especially attractive options. They can be installed relatively quickly (compared to construction of a new baseload plant) and in a modular fashion. This would allow a utility to carry out its construction program in smaller increments to meet projected demand growth. And it will help ensure that consumers are not confronted with another cycle of "rate shock" caused by bringing large, new baseload plants into service.

With these repowering technologies, utilities can use much of the balance-of-plant equipment in the aging plant, increase its power output by as much as 150 percent, extend its useful lifetime, and greatly reduce SO_2 and NO_x emissions. The technologies are relatively insensitive to coal type and can be installed on most existing coal-fired power plants.

Those utilities confronted with possible requirements for further emission controls will also benefit from the emergence of an expanded slate of retrofit clean coal technologies.

Today, if more stringent environmental controls were to be imposed on existing facilities, utilities would be limited to three options -- flue gas scrubbing which is very costly, switching to low-sulfur coals which could create severe socio-economic impacts, and coal cleaning which is limited in reducing SO_2 emissions.

The expanding slate of innovative clean coal retrofit technologies should provide substantially improved options that are preferable to the choices available today. These new technologies offer the flexibility to be used individually or in combination with one another to achieve emissions control of both SO_2 and NO_x. They provide cost-effective options for the diverse inventory of coal-fired power plants, including those that are limited in available space. They permit the full range of coals to be used in small, moderate or large size boilers. And they produce waste products that are more easily and safely disposable or, in some cases, saleable.

Finally, the availability of demonstrated clean coal hardware can give America a substantial marketing advantage overseas. Worldwide consumption of coal is expected to increase by more than one-third between now and the end of the century, primarily because of increasing coal-fired electric generating capacity. As in the U.S., growth in the demand for coal by many industrialized and developing nations will likely be accompanied by increasing concerns over environmental impacts. The improved coal technologies being developed and demonstrated in the U.S. will be able to meet the environmental objectives of the international community.

Moreover, because America's clean coal projects will provide commercial-scale performance data using U.S. coals, the potential exists to link U.S. coal exports and U.S. technology in a way that enhances America's competitiveness in both. The "packaging" of U.S. coal and the technology to use it cleanly and efficiently can become an important byproduct of the nation's clean coal technology program.

This completes my formal statement. I will be pleased to answer any questions the Committee may have.

Clean Coal Technology Program History
CHRONOLOGY OF MAJOR EVENTS

Major Event	Date
"Section 321" Program Announcement:	
Pub. L. No. 98-473 Signed into Law	Oct. 12, 1984
Program Announcement Published in *Federal Register* (FR)	Nov. 27, 1984
Closing Date for Receipt of Submittals	Feb. 15, 1985
Report to Congress Issued	May 1, 1985
Supplemental Report to Congress Issued	Sept. 6, 1985
Clean Coal Technology Program Opportunity Notice:	
Pub. L. No. 99-190 Signed into Law	Dec. 19, 1985
PON Announcement Published in FR	Jan. 27, 1986
Draft PON Issued for Public Comment	Jan. 30, 1986
Due Date for Public Comments	Feb. 6, 1986
Final PON Issued	Feb. 17, 1986
Amendment to Final PON Issued	Feb. 24, 1986
Preproposal Conference	Mar. 6, 1986
Closing Date for Receipt of Proposals	Apr. 18, 1986
Public Abstracts Released	Apr. 21, 1986
Source Selection Official's Selection Statement Issued	July 24, 1986
Comprehensive Report to Congress Issued	Aug. 21, 1986
Report to Congress on "Relationships/Acid Rain" Issued	Oct. 24, 1986
The Present "Retrofit" Informational Solicitation:	
Pub. L. No. 99-500 Signed into Law	Oct. 18, 1986
Program Announcement Published in FR	Nov. 12, 1986*
Department of Energy News Release Issued	Nov. 14, 1986
Closing Date for Receipt of Submittals	Jan. 12, 1987
Department of Energy News Release and Public Abstracts Issued	Jan. 16, 1987
Summary Report to Congress Due	Mar. 6, 1987*
Second Report to Congress Due	May 12, 1987*

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* In accordance with Pub. L. No. 99-500, which provided that the *Federal Register* (FR) Notice be issued "no later than thirty days after the date of the enactment of this Act," that the Department of Energy, "no later than March 6, 1987, submit to Congress a summary report ...," and that the Second Report be submitted "no later than one hundred and twenty days after the receipt of such statements and proposals."

TESTIMONY

MARY L. WALKER

ASSISTANT SECRETARY FOR ENVIRONMENT, SAFETY AND HEALTH

U.S. DEPARTMENT OF ENERGY

SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

UNITED STATES SENATE

MARCH 11, 1987

Good Morning. I am pleased today to discuss the Administration's, and particularly the Department of Energy's, activities in implementing the recommendations in the January 1986 Joint Report of the Special Envoys on Acid Rain. As the Department's environmental policymaker, my involvement in acid rain, as well as other national environmental issues, is comprehensive. For example, and directly on the subject of today's hearing, Mr. Wampler and I are DOE participants in the BACG - the Bilateral Advisory and Consultative Group - established as a result of the Envoys' recommendation for a bilateral group to provide a forum for discussion and first-level consultation on issues related to transboundary pollution.

My testimony today will draw from the Envoys' report, its findings and recommendations, and will provide a status report on the Administration's activities in implementing the Envoys' recommendations. The status of the Department's specific activities in the Clean Coal Technology demonstration Program have been addressed by Allen Wampler, the Department of Energy's Assistant Secretary for Fossil Energy.

The Envoys' Findings and Their Context

After over nine months of concentration on the scientific, economic and political aspects of the acid rain issue, Acid Rain Special Envoys Drew Lewis and William Davis, stated their findings in January 1986 as follows:

> - Acid rain is a serious environmental problem in both the United States and Canada. Acidic emissions transported through the atmosphere undoubtedly are contributing to the acidification of sensitive areas in both countries. The potential for long-term socio-economic costs is high.
> - Acid rain is a serious transboundary problem. Air pollutants emitted by sources in both countries cross their mutual border, thus causing a diplomatic as well as an environmental problem.
>
> At the same time, we also learned something very important about potential solutions to the acid rain problem:
>
> - At the present time, there are only a limited number of potential avenues for achieving major reductions in acidic air emissions, and they all carry high socio-economic costs.
>
> Thus, acid rain is not only an environmental and technical problem, but one with far-ranging socio-economic and political implications which are different in the United States and Canada. ("Joint Report of the Special Envoys on Acid Rain;" January 1986, page 6)

The Envoys followed this statement of findings in their report with a section that separately summarized the U.S. and Canadian perspectives on acid rain. In introducing the differences between the two countries' perspectives, the Envoys reiterated that, while acid rain is a shared environmental problem to which each of the two countries contribute, each country is affected in different ways and each country must, necessarily, respond in different ways.

The context for their recommendations for further action is stated quite clearly by the Envoys:

> In preparing our recommendations, we have been conscious of the wide differences between our two countries on this issue. We have also kept in mind that our mandate was not to find a final solution ... but to find ways to which our two countries can begin to move together ...
>
> For such progress to be possible ... our recommendations must be realistic. They must not ask either country to make a sudden, revolutionary change in its position. ... They must instead point the way to a resumption of fruitful bilateral dialogue and constructive action ... ("Joint Report," page 29)

Thus, the Envoys were not providing a final solution to the "acid rain problem" -- nor were they asking either the U.S. or Canada to immediately change its views or policies. Rather, their recommendations were designed to reopen the dialogue between the two nations, and begin useful steps to resolve their differences and initiate preparations that would increase the effectiveness of any actions later found to be necessary.

The Envoys' recommendations for this dialogue and constructive action were in three areas: cooperative activities, innovative control technology, and research. Cooperative activities recommendations were for each country to review its existing air pollution programs for ways to address transboundary concerns, for each country to notify the other of pending changes to these programs or their enabling legislation, for the acid rain issue to remain high on the agenda of meetings between the President and Prime Minister, and for the establishment of a high-level bilateral advisory group to advise the diplomatic and environmental officers of each country.

The innovative technology recommendation for a five-year, five billion dollar control technology demonstration program was based on the Envoys' conclusion that "if the menu of control options were expanded, and if the new options were significantly cheaper yet highly efficient, it would be easier to formulate an acid rain control plan that would have broader public appeal." ("Joint Report", p. 29)

The Envoys' recommended demonstration program has as its most important goal the expansion of the slate of available SO2 and NOx control technologies, with near-term emissions reductions a secondary goal. Their recommended program would place special consideration on projects with the greatest emissions reductions, with maximum cost-effectiveness, with retrofit and high sulfur coal capabilities. They also recommended a high-level U.S. panel, with State and Canadian representatives, to oversee and select these projects.

The Envoys' scientific research recommendation suggests six areas where scientific research would be of special value to policy decisionmakers: 1) development of a comprehensive dry deposition monitoring network for North America; 2) watershed process data on development and testing of a predictive model for watershed response to acid deposition; 3) quantification of the relationship between surface water acidity changes and changes in aquatic biota; 4) investigation of the potential link between forest decline and acid rain; 5) increased research on acid rain effects on materials; and 6) emphasis on the potential human health and aquatic/forest effects of heavy metals mobilization in acidified surface water.

Recommendations to Close the Gap in Views

The resumption of bilateral discussions -- the fruitful dialogue -- is well underway. As the Envoys recommended, the Bilateral Advisory and Consultative Group (BACG) was established to provide a forum for first-level discussions, as well as advice to the diplomatic and environmental management officials. Chaired by officials of the U.S. and Canadian foreign affairs departments, the BACG has met three times, beginning last June and most recently on February 25, 1987. A BACG report on the first year's activities is being prepared.

In addition to the BACG meetings, the BACG Chairmen and the counterpart agencies in the two countries have maintained active interchanges. Aspects of the acid rain issue have been periodically discussed between the respective Secretaries of State and environmental chiefs, the most recent discussion during yesterday's meeting between Secretary of State Shultz and Canadian Minister for External Affairs, Joe Clark. As you know, Canada raised their concerns regarding the U.S. pace on implementing the Envoys' Report in January and the Vice President met with Prime Minister Mulroney on January 21 on this issue. As a result of this meeting, the Vice President called for a review in which we would take a "fresh look" at our progress in meeting the commitments made by the President when he endorsed the Envoys' Report. This review by the Administration is underway; I anticipate that the results of that fresh look will be part of the discussions between the President and the Prime Minister in Ottawa in early April.

To foster dialogue on innovative technologies, DOE has met with Canadian officials to discuss the Department's current and proposed programs. Secretary Herrington met last December with Canadian Environment Minister McMillan on this subject. We anticipate that specific and detailed technology discussions will be continued in a meeting of DOE and Canada's Department of Mines and Resources staff members later this month or in April. Environment Canada officials have scheduled recurring meetings to discuss bilateral environmental topics.

Both the U.S. and Canadian governments, as recommended by the Envoys, are in the process of reviewing their existing air pollution programs to identify opportunities to address transboundary air pollution concerns, consistent with existing law. The Environmental Protection Agency study of these programs will be included in the joint BACG Report.

The Envoys also recommended timely notice to the other country of proposed changes in one country's laws or regulations which may affect the other country. The procedures that have been in place since 1982 -- for example, those by which EPA informs Canada through the Embassy of Canada of major proposed and final policy and regulatory decisions -- have been judged to successfully meet this recommendation. In addition, under special circumstances, EPA has provided specific briefings to the Canadian government, through either the U.S. Embassy in Ottawa or the Canadian Embassy here in Washington, on proposed or final policy and regulatory decisions.

The Innovative Controls Program -- Expanding the Menu of Control Options

Assistant Secretary Wampler has described the technology and programmatic details of the "National Clean Coal Program" -both the current program and the plans for its future. Further, he has provided a general discussion of the total national effort as it is documented in the recent DOE report, "America's Clean Coal Commitment." I will discuss the relationship of this program to the Envoys' recommendation for a control technology demonstration program.

The President, in his endorsement of the Envoys' Report last March, emphasized that this recommendation was in the context of the extensive clean coal technology program already underway. He noted that Congress had mandated and the Administration was in the process of selecting our first series of cofunded Clean Coal Technology Programs (CCTP-1). The Administration judged that embarkation upon a new federal demonstration effort before the selection of projects under the $400 million first phase of the CCTP and an inventory of related federal, state and private research and demonstration activities underway or planned, was premature and potentially wasteful. We stated this to Canada in the first BACG meeting last June. Therefore, our implementing actions to support the technology demonstration recommendation have focussed over this past year on identifying and advancing existing efforts in this area. A chronology of these efforts and planned future efforts illustrates the responsiveness of these activities as "part of a long-term response to the transboundary acid rain problem," as the Envoys stated the principal goal of this recommendation.

Nine projects have been selected for negotiation, all of which employ technologies which reduce SO2 and/or NOx emissions compared to competing technologies. On October 24, 1986, the Department submitted a report to Congress on how the projects selected in this first phase of CCTP respond to the Envoys' recommendation and proposed selection criteria, indicating that although there appeared to be differences in direction and focus of the Congressionally-directed effort and the Special Envoys' recommended effort, all nine of the selected projects met at least two of the criteria recommended for use in project selection by the Envoys' program.

Remembering that near-term reductions were not a Congressional directive for CCTP-1, others have estimated that the potential that could be achieved by the nine selected projects is 35,000 to 56,000 tons of sulfur dioxide (SO2) per year. At least five of the project technologies appear applicable as retrofit or repowering technologies, to older existing plants and their use would reduce emissions well below current legal and regulatory requirements.

The Administration's budget request for CCTP-2 and projected CCTP-3 phases, developed after the Envoys' Report was available, are directed specifically to retrofit, repowering and modernization technologies. This phased program of sequential solicitations will permit the U.S. to intelligently evaluate the results of each set of projects, building a broader base of technology options and clearly identifying where gaps in the menu of options occur which would profit from demonstrations.

Focussing and Coordinating Scientific Research

The Envoys' recommendations to close the gap -- to narrow the differences -- included scientific research. Research to sufficiently narrow scientific uncertainties regarding the emissions, transformation, transport and impact of acid deposition pollutants is the keystone of the Administration's acid rain policy. The U.S. is committed to act to control acid rain once it is reasonably certain that the action will achieve its intended results, and that those results will justify the social and economic costs entailed. The Administration has reiterated that research will provide the information necessary to make a prudent decision on the need for or design of additional emissions controls beyond those already required by current Clean Air Act implementation.

The Envoys noted that "scientific information provides a basis for determining the most effective actions to address the damage caused by acid rain and other long-range, transboundary air pollutants." Effective and increased cooperation and collaboration has been initiated between the principal acid rain research units of the two governments -- the U.S. National Acid Precipitation Assessment Program (NAPAP) and the Canadian and Federal Provincial Research and Monitoring Coordinating Committee (RMCC). These groups are preparing a joint report which reviews research efforts, the scientific advances due to this research, and their joint efforts to strengthen joint research activities. I anticipate that their report will be released later this month.

If this and later research indicates that the resolution of the acid rain problem must involve a strengthening of or additions to United States emissions control requirements, the availability of less socially and economically disruptive and costly technology options would provide the revised program the "broader public appeal" that current emissions reduction options do not allow. Economic and environmental common sense can together resolve many differences of view. If added regulatory programs are not required, the most cost-effective of the options are expected to support the existing emissions control programs; for example, by expanding adequately-demonstrated technologies available for compliance with New Source Performance Standards, with lower emissions rates achieved through the use of more cost-effective technologies.

Domestic and International Concerns Are Met by the Envoys' Recommendations

The implementation of the Envoys' recommendations will further the process for resolving acid rain concerns. The focussed research recommended by the Envoys, and underway since 1981, will narrow the uncertainties surrounding the causes of lake acidification and building materials and forest damage, both current and projected. The annual levels of sulfur dioxide emissions have decreased since the early 1970's and preliminary indications are that they decreased from 1984 to 1985 -- during a period of economic and energy demand growth. DOE believes they are likely to decrease further in the long-term as a result of Clean Air Act requirements already in place, including the stringent control programs on our future facility replacements and additions.

The Envoys' recommendations and the implementing activities described today, have established a meaningful process that is working, and our current scientific understanding tells us we have the time to follow through on this process. Innovative controls can be ready for deployment, with improved economic and environmental characteristics, in the mid-1990s. The first results of the Clean Coal Technology Program should be available at the time when research results sufficiently define what, if any, further emissions control and related steps are necessary. Until that time, the clean coal program is providing new and improved options that meet the many needs of this country's energy and environmental future.

This completes my formal testimony. I will be happy to answer any questions you may have.

TESTIMONY OF
J. CRAIG POTTER
ASSISTANT ADMINISTRATOR FOR AIR AND RADIATION
U.S. ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
UNITED STATES SENATE

MARCH 11, 1987

Good Morning Mr. Chairman and Members of the Subcommittee. I am pleased to be here this morning to speak with you about EPA's role in the development of clean coal technologies: cost-efficient, removal-efficient sulfur dioxide (SO_2) and nitrogen dioxide (NOx) control technologies for coal-fired boilers. With me this morning is Frank Princiotta, Director of EPA's Air and Energy Engineering Research Laboratory in Research Triangle Park, North Carolina.

Extensive United States coal reserves ensure that the United States will be self-sufficient in this vital energy resource for many years to come. We are all concerned that coal be used in a way that is protective of the public health and the environment. Certainly, clean coal technologies can help in this cause.

The EPA and its predecessor agencies have been involved in development and demonstration of SO_2 and NOx control technologies primarily for new coal-fired utility and industrial boilers for over 20 years. Until recently the Agency's work in this area has focused on technologies which supported the development of New Source Performance Standards (NSPS) for these sources. This work helped to facilitate both development and demonstration of a number of technologies for SO_2 and NOx control, including:

1. Several flue gas desulfurization (FGD) or scrubber systems for high efficiency control of SO_2 from coal-fired utility boilers;
2. The addition of specific organic acids to FGD systems, to improve the operability and SO_2 control efficiency of the systems and reduce costs; and
3. Low NOx firing systems, which offer an effective low-cost approach to controlling nitrogen oxides.

These technology types are the current state-of-the-art emission control technologies for new utility boilers. In addition, these technologies can be retrofitted on existing boilers. In our view, the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application. Approximately 65% of the SO_2 emissions in the U.S. currently come from coal-fired power plants. This figure gains additional significance because of the recent practice of rehabilitating and repowering these plants, thus increasing their useful life. Life extension of these plants by two or more decades beyond what was previously anticipated may alter one of the Clean Air Act's fundamental assumptions concerning control strategies: that new sources subject to more stringent New Source Standards will replace existing sources, thereby producing continuing reductions in overall emissions in the near or middle term. Another reason for our focus on retrofit technologies stems from the concern over SO_2 and NOx as they relate to the acid rain debate. Because such a high percentage of these pollutants are emitted from existing coal-fired boilers, we believe it is appropriate to focus Federal resources on technologies which could affect these emissions. Finally, the Joint Envoys' report included a recommendation stating that "more consideration should be given to projects that demonstrate retrofit technologies applicable to the largest number of existing sources..., [and] special consideration should be given to technologies that can be applied to facilities currently dependent on the use of high sulfur coal."

In recognition of the fact that additional lower-cost approaches might be required for certain elements of the existing boiler population, the Agency has been working more recently on technologies with the potential for low cost, moderate to high SO_2 control for existing boilers, as follows:

1. The EPA has developed the LIMB (Limestone Injection Multistage Burners) process which uses low NOx burners for NOx control and furnace sorbent injection for SO_2

control. LIMB is particularly attractive as a retrofit technology because it is quite low in capital costs, could remove up to 50-60% of SO_2 and NOx at a lower capital cost than FGD, and requires little room for retrofit. Several process improvements are being evaluated to further enhance LIMB's SO_2 removal and/or to reduce cost.

2. The Agency has developed several other technologies for lower-cost SO_2 control including, the E-SOx process (a low cost, SO_2 removal-efficient technology which can be retrofitted into boilers which presently use electrostatic precipitators), and improved sorbents for Lime Spray drying (dry FGD) and duct injection.
3. The EPA has performed basic bench and pilot scale development on reburning technology for NOx control. This technology involves the addition of secondary fuel and air above the primary combustion zone, and it can reduce NOx emissions by 50% or more.

Current EPA Projects for Retrofit SO_2 and/or NOx Control

The EPA currently is pursuing projects for development and/or demonstration of promising innovative SO_2 and/or NOx control technologies which are potentially responsive to the criteria of the Special Envoys' recommendations. I will briefly discuss selected projects:

A. LIMB. The LIMB project has developed the basic technology for retrofit of coal-fired utility boilers and two demonstration projects (wall-fired and tangentially-fired) are being implemented.

1. The wall-fired boiler demonstration is scheduled to begin operation in mid-1987 at the Edgewater plant of Ohio Edison. Following installation of the LIMB system, an SO_2 control performance optimization period will commence. Based on these tests, LIMB operating procedures will be established and the system operated for an extended period (until mid-1988) with the boiler following normal load swings. In addition, several process modifications to improve SO_2 capture will be evaluated as part of the testing. This project is cofunded by the State of Ohio, Babcock & Wilcox, Ohio Edison and Conoco. A DOE Clean Coal Technology project will extend this effort.

A tangentially-fired boiler demonstration procurement has also been initiated; however, final contract negotiations have not been concluded. This project is similar in scope to the wall-fired project.

B. E-SOx. The E-SOx process uses advanced Electrostatic Precipitator (ESP) technology to free up duct space. A sorbent slurry is injected into the space provided for SO_2 capture. Small pilot scale testing shows the potential for 50-70% SO_2 capture in selected existing ESP's with capital costs significantly less than conventional FGD. A large pilot scale demonstration has been selected for negotiation under the State of Ohio coal technology program by Babcock & Wilcox with the EPA as a cosponsor. When the project is successfully negotiated, EPA will provide equipment and research and development support.

C. Reburning. The EPA is in final negotiation for a project to demonstrate reburning technology for NOx control on a cyclone-fired boiler. The goal is to achieve 50-70% NOx control on a class of boilers that are not readily adaptable to low NOx burner concepts. The project will be cofunded by Electric Power Research Institute (EPRI) and Gas Research Institute (GRI).

Relationship between Clean Coal Technologies and Acid Rain Precursor Control

There is no consensus, as yet, on whether acid precipitation precursor control is needed or the control technology strategy that may be required to achieve a given level of control. In fact, the level of any required control and its timing would have a direct impact on the technology mix that would achieve the goal at the least possible cost.

In general, there are three ways of applying SO_2 reduction technologies which might be elements of any control strategy: 1) retrofit of existing boilers; 2) repowering of existing boilers; and 3) advanced technologies for new power plants. Some technologies can be used for more than one of these projects. Each of these is briefly discussed below:

A. Retrofit of existing boilers. Retrofit technologies may be defined as those which can be added to existing boilers with relatively modest changes to the balance of the boiler system. The existing boiler population is composed of a wide range of individual units, each with specific characteristics that will influence the choice of retrofit technologies. Certain segments of the population may be well suited for conventional FGD; whereas, for another segment, the innovative technologies (e.g., LIMB) may be preferred.

B. Repowering of existing boilers. An alternative approach for certain existing boilers is repowering, which typically involves replacing the existing boiler and firing system with a steam generator of another design. In many cases, repowering boosts the generating capacity of a plant anywhere from 50% to 150%. Thus the economics of repowering may make it attractive for power boosts and in some cases emission reductions.

C. Advanced technology for new plants. As existing plants are replaced by new plants with state-of-the-art SO_2 and NOx control, emission reductions will occur. There are emerging technologies which can potentially increase the level of SO_2 control achievable on new plants. One of the commonly mentioned technologies for new plants or for repowering is Integrated Gasification Combined Cycle (IGCC) which has the potential to achieve higher thermal efficiency and greater control of SO_2 and NOx than conventional power plants. Promising results have been achieved at the Coolwater plant.

The relative role of the three ways of applying advanced technologies would strongly depend on any determination made with regard to the level and timing of emission reductions. If major SO_2 and NOx reductions are required in the next 10 to 20 years, we believe that retrofit technology will dominate with repowering playing an important role. If the time frame for any major reductions is extended to 30-40 years, then advanced technology for new plants will become much more significant.

In addition to its independent work in the development of clean coal technologies, EPA has been working with the Department of Energy (DOE). In round one of the Clean Coal Technology (CCT) program, EPA provided assistance in proposal evaluation. EPA provided a staff member to serve as a member of the Technical Evaluation Committee (TEC) for five proposals dealing with flue gas treatment. In addition, a Laboratory Director from EPA's Office of Research and Development evaluated the environmental aspects of all viable proposals as a consultant to the DOE's Source Evaluation Board (SEB). EPA did not have a role in the final selection process nor will it have any technical management role for the selected clean coal projects.

EPA and DOE also have responsibility for responding to separate portions of the Joint Envoys' recommendations. The Joint Envoys made recommendations in several areas, including commercial demonstration of clean coal technologies, and bilateral consultation.

EPA has the lead role in implementing one aspect of the bilateral consultation recommendation -- a review of existing air pollution control legislation and programs. This review of existing authorities is currently undergoing Agency review and should be completed shortly. With regard to the demonstration of innovative control technologies, the Joint Envoys' report recognized that a more diverse and less expensive set of technologies would help in developing a consensus on the acid rain issue, and DOE has been given the lead in implementing the commercial demonstration recommendation of the Joint Envoys. We believe that the implementation of the program in the Joint Envoys' report that the President has endorsed can provide the needed, less expensive control options.

That concludes my prepared remarks Mr. Chairman. Mr. Princiotta and I would be glad to answer any questions that you may have.

NATIONAL
CLEAN AIR
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Testimony by

David G. Hawkins

NATURAL RESOURCES DEFENSE COUNCIL

on behalf of the

NATIONAL CLEAN AIR COALITION

before the

Subcommittee on Environmental Protection
Committee on Environment and Public Works
U.S. Senate

March 11, 1987

Thank you for the opportunity to testify on the U.S. "clean coal" demonstration program, the implementation of the 1986 Report of the Special Envoys on Acid Rain, and the relationship of these activities to acid rain control legislation.

Let me state the National Clean Air Coalition's view at the outset of my remarks. Over two decades of research have produced a range of fully demonstrated methods to reduce acid rain precursor emissions. Today's available control methods are adequate to achieve in a reliable and affordable fashion, any level of emission reductions proposed in this or the last several Congresses. The additional "clean coal" demonstration projects now underway may prove out several useful methods to complement the current mix of control methods. However, this "clean coal" demonstration program is not, as claimed by acid rain control opponents, reason to delay enactment of a law requiring emission reductions on a prompt schedule.

I. Relationship Between "Clean Coal" Demonstrations and Acid Rain Control

Since 1980 opponents of acid rain control have trotted out a series of arguments against a new law: there is no problem; we don't understand the cause of the problem; somebody else causes the problem; we don't know how to fix the problem or we can't afford to do it. As the weaknesses of these arguments have been exposed, control opponents have turned to what is traditionally the last weapon in their arsenal of delay: they predict a vastly superior solution to the problem just over the horizon and urge Congress to wait until it arrives.

Those who argue we should "wait for clean coal technologies" base their case on several claims that do not withstand analysis:

First, they claim that current control methods are unacceptable means to pursue a control program;

Second, they claim that superior methods with wide potential applicability are on the verge of commercialization; and

Third, they claim that the "clean coal" grant program will be sufficient to accelerate such commercialization, while the schedules in pending control bills will insure that emerging technologies are ignored.

I would like to address these claims in turn.

1. Current control methods can do the job.

The argument that we must wait for better control methods is not a new one. Essentially the same argument was made twenty years ago to the predecessor of this Subcommittee by the same industries that are now most vigorously opposing acid rain controls. Then, as now, the issue was should the federal government require a major reduction in emissions from the electric utility and other major industries. The utility and coal industries argued then for delay and promoted tall stacks as the "solution that buys us the time required to carry out the research that may one day give us still better solutions."[1] Coal industry witnesses pointed to the emerging technology of flue gas desulfurization (FGD) as a method that, with 3-5 years of additional development work, could be used to attack the coal sulfur problem.[2]

Well, FGD systems and other methods were developed and improved through the 1970s and are now proven reliable means of controlling both new and existing plants. However, now that we have been through two decades of development and refinement of FGD and other control systems, these "emerging technologies" of twenty years ago are derided, and our attention is once more directed to methods that have not yet arrived.

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[1] "Air Pollution - 1967," Hearings before the Subcommittee on Air and Water Pollution, Committee on Public Works, U.S. Senate, 90th Cong., 1st Sess. (1967) at 2046. (Statement of Philip Sporn, American Electric Power Co., Inc.).

[2] Id. at 2023, 2041, 2442.

Today's proven utility sulfur dioxide (SO_2) control technologies include third-generation "wet" FGD systems ("scrubbers"), regenerable FGD systems, spray dryers, atmospheric fluidized bed combustion (AFBC), coal cleaning, and fuel switching. Together, these techniques can achieve SO_2 reductions of 10-12 million tons, as called for in pending control legislation. Proven methods for nitrogen oxides (NOx) control include AFBC and several catalytic and non-catalytic flue gas cleanup techniques discussed at last week's hearing before the Subcommittee.

Opponents of acid rain controls charge that today's technologies are too expensive. However, their assessments exaggerate the true costs of these technologies. By using high capital cost assumptions for FGD systems, applying high capital charge rates and other misleading accounting techniques, and by assuming installation of far more FGD capacity than would be required to achieve required reductions, analysts have been able to generate very high cost estimates. An April 1986 Congressional Research Service staff critique of the Edison Electric Institute's analysis of H.R. 4567 shows that such techniques can double or triple estimated control costs.[1]

For example, most government and industry studies have assumed FGD capital costs of $200-250 per kilowatt or higher. However, these estimates are based on engineering designs that rely on large amounts of spare scrubber module capacity and do not use additives to improve scrubber efficiency. Based on actual installation experience of recent U.S. FGD systems, a cost of $150 or less per kilowatt is appropriate.[4] In addition, even the Electric Power Research Institute's (EPRI) latest cost estimates for a new 500 mw high-sulfur coal FGD system with additives has dropped to $129 per kilowatt.[5] Since this EPRI figure contains significant spare scrubber capacity and very large allowances for "contingencies," it should be regarded as a high-side estimate.

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[1] CRS Staff Report, "Estimating Acid Rain Control Costs: Illustrative Problems from the Recent EEI-TBS Study of H.R. 4567," April 29, 1986.

I would also like to call the Subcommittee's attention to the acid rain control program now being implemented in West Germany. Under legislation enacted in 1983, every large coal-fired plant in West Germany which will operate past 1993 is being required to install and operate a high-efficiency FGD system by the beginning of 1988. Thus, less than nine months from today, West Germany will have fully implemented a wholesale FGD retrofit program. Scores of these systems have been ordered and are now under construction.[6] Cost information from West Germany shows capital costs of about $100 per kilowatt for a typical 350 megawatt retrofit, with lower unit costs for larger plants.[7]

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[4] See Peabody Process Systems, "Acid Deposition Control: Economical Retrofit of Wet Scrubbers to Coal Fired Boilers," March 1986, at p. 6. Exhibit 1 to this testimony. (Retained in committee files.)

[5] EPRI, Economic Evaluation of FGD Systems, Vol. 5, October 1986 at page 7-35 (Dec. 1982 dollars).

[6] See Wm. Ellison, "Survey Report and Assessment of Utility Flue Gas Desulfurization Systems Installation in Europe," Ninth EPA/EPRI Symposium on Flue Gas Desulfurization, Cincinnati, Ohio, June 4-7, 1985. Tables 1-4 of the Ellison paper summarize Germany's control requirements and FGD systems ordered as of year-end 1984. (Attached.)

The Coalition neither advocates nor opposes a wholesale FGD retrofit program or any other technology-specific solution to acid rain. However, West Germany, which like the United States depends heavily on domestic coal and competes vigorously in international trade, is demonstrating that such a strategy is technically and economically feasible and can be implemented more rapidly than the schedule contained in any bills now pending in Congress.

The reductions required by the pending bills would not require universal use of FGD systems, but rather, could be complied with by using a mixture of available controls, including conventional FGDs, regenerable FGDs, spray dryer systems, repowering with AFBC, coal cleaning, continued use of low sulfur fuels and, to the extent Congress decides is appropriate, fuel switching.

2. Applicability of "Clean Coal Technologies."

A plant-by-plant list of the information summarized in the Ellison paper is also attached. The list, in German, contains columns that, from left to right, identify the plant name and operating company, plant size and fuel type, FGD vendor and FGD type, percentage of flue gas treated, FGD byproduct, and FGD operation date. (Retained in committee files.)

[7] Bernd Schärer and Norbert Haug, "The cost of flue gas desulphurization and denitrification in the Federal Republic of Germany," Fourth Seminar on the Control of Sulfur and Nitrogen Oxides from Stationary Sources, Graz, Austria, May 12-16, 1986.

Advocates of "clean coal" technologies can describe a long list of concepts in varying stages of development but most of these concepts will apply primarily to new plant or repowering projects. To control acid rain we must reduce emissions from the roughly 200 gigawatts of pre-NSPS coal and oil utility plants. Most of these plants have operated for less than half of their estimated useful life and significant reductions due to retirement cannot be expected until the end of the first quarter of the next century. Life extension programs could push reductions from retirements even further into the future.

The relevant question to ask about emerging technologies and acid rain control programs is, thus, how many technologies suitable for retrofit application is the industry today ready and willing to attempt to demonstrate commercially? The answer to this question can be gleaned from the submissions made to the Department of Energy (DOE) in response to DOE's February 1986 $400 million "clean coal" program solicitation and, more speculatively, from DOE's November 1986 "retrofit" program announcement.

Five proposals submitted for the "first round" DOE program appear to represent commercial-scale demonstrations of retrofit technologies with potentially wide application. These proposals included furnace sorbent injection demonstrations by Babcock & Wilcox (B&W) and the Energy and Environmental Research Corp. (EER), as well as a combination proposal from TRW, Inc. to demonstrate, at separate sites, components of an integrated furnace sorbent injection and spray dryer system. The B&W proposal would support two years of additional testing of the sorbent injection demonstration system now being installed at Ohio Edison's Edgewater plant. The B&W and EER proposals were selected by DOE in August 1986, while the TRW proposal was not selected.

In addition to these three proposals, TVA proposed to demonstrate a spray dryer system on medium and high sulfur coals at its Shawnee plant. It is not clear that the TVA demo is needed to commercialize application of spray dryer technology to eastern coals, given the experience already gathered at other utility and industrial plants. EPA's 1986 proposed NSPS for industrial boilers regards spray dryer systems as demonstrated conventional technology capable of achieving a 90% reduction in SO_2 on any type of coal.

The fifth commercial-scale retrofit proposal was submitted by Recovery Systems, Ltd. for a regenerable FGD system that produces fertilizer.

Another advanced FGD system with retrofit potential was proposed by NOXSO Corp. However, this proposal is limited to a pilot scale of 5 megawatts electric of flue gas. This represented a scaling back from NOXSO's February 1985 submittal, which proposed a 100 megawatt commercial demonstration of this technology, contingent on locating a host utility.

In addition to the above proposals, nine proposals for fluidized bed boilers (seven atmospheric and two pressurized) were submitted. While atmospheric FBC units appear to be an attractive alternative for smaller, older units undergoing repowering for life extension programs, FBC is unlikely to be an economically competitive option for the many larger pre-NSPS units built between 1960 and the mid-1970s. Moreover, at least three utilities have already independently committed to commercial construction of AFBC units, indicating that the industry itself regards this technology as demonstrated.

Another potential retrofit technology is the so-called "advanced combustor." A small scale demonstration proposal for an industrial boiler was selected by DOE in the "first round" program.

The Congressional Research Service analysis of the DOE "first round" selections concludes that only the B&W, EER and Coal Tech advanced combustors have significant retrofit potential.[8]

DOE's November 1986 program announcement has produced 139 "Statements of Interest."[9] Since the DOE announcement stated that no monies were available to fund any submissions received, the submissions do not represent formal commitments by the proposers to carry out any of the described projects. When and if DOE actually publishes a funded program announcement fewer responses may result. (A similar, unfunded DOE announcement in 1985 elicited 175 responses, while the follow-up, funded February 1986 announcement resulted in only 51 proposals.)

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[8] See CRS, "Acid Rain, DOE's Clean Coal Technology Program and the Lewis-Davis Report: Squaring A Circle?," January 21, 1987.

[9] See March 6, 1987 DOE "Summary Report to Congress on Emerging Coal Technologies Capable of Retrofitting, Repowering or Modernizing Existing Facilities."

Nevertheless, the most recent submissions do provide some useful information on potential retrofit methods. There are a few proposals for full utility-sized demonstration of the "advanced combustor" technology that DOE has committed to fund at the smaller industrial boiler scale. There are a number of additional furnace sorbent injection proposals and several duct sorbent injection proposals. In addition there are several proposals for refinements to conventional FGD systems.

In short, based on the responses to the DOE program announcements, industry appears prepared to construct commercial-scale versions of several technologies (sorbent injection systems, spray dryers for higher sulfur coals, "advanced combustors" and refined FGD systems) that may have broad applicability to the retrofit market. While use of these systems would complement current conventional controls (in our view, spray dryers and several of the refined FGD systems are already demonstrated technology), there is no basis for a claim that delaying acid rain controls is either necessary or sufficient to promote rapid application of these methods.

3. Control Program Delays Will Delay Demonstrations of Emerging Technologies.

There is no conflict between pending acid rain control bills and completion of the demonstrations of the retrofittable technologies discussed above. To the contrary, delaying passage of a new law will create incentives to reduce efforts to successfully prove out these additional control methods.

Two of the major systems receiving industry attention, sorbent injection and spray drying, have already received limited commercial demonstration. Additional work can be completed in two to four years with sufficient industry interest so that results can be made available prior to even the earliest mandatory date for achieving emission reductions in most pending control bills. The B&W and EER furnace sorbent injection projects selected by DOE will have fully evaluated operational results completed within 43 and 48 months respectively and will begin operation well before that date. The Coal Tech advanced combustor will be demonstrated in 27 months; similar utility-scale advanced combustor proposals just submitted to DOE have 2-3 year schedules for reporting operational results.[18]

Under S. 321, the Chairman's bill, reductions are not required for sources using control technologies until 1996. States must adopt emission limits within two years of enactment. Therefore, sources that wish to preserve an option for use of an "emerging" technology would make a conservative estimate of the technology's emission reduction potential prior to that time and seek a source-specific emission limit that would be achievable, given the technology's assumed reduction potential. Sources needing to control by 1996 would probably need to make a construction decision by 1993-94. Based on the information presented in the DOE abstracts, results from the furnace sorbent injection, duct sorbent injection, advanced combustor, refined FGD and spray dryer demos will be available by 1991 or earlier.

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[18] See, e.g., DOE March 6, 1987 Summary Report at 134-137 (TRW and Ohio Edison combustor proposals).

Passage of acid rain control laws in this Congress will insure that industry treats the potential for use of emerging controls as a serious matter. Confronted with the need to plan for a real emission reduction program, the industry will have a genuine incentive to pool the resources required to provide prompt answers to reduce any technical risks associated with emerging technologies.

In contrast, if acid rain control schedules were linked to some unspecified level of proof that new technologies were demonstrated, the industry would have an enormous incentive to delay such demonstrations and to characterize the results of any demonstrations as not sufficiently conclusive. All the while, damages caused by acid rain would continue.

Mr. Chairman, American taxpayers would not appreciate a proposal to spend billions of their dollars on a program to prove that emerging technology does not work. Yet this would be the most likely outcome of any "clean coal" demonstration program that is linked to a delay in control requirements pending "adequate" results. Under such an approach, industry would know that "success" would bring on new regulation while "failure" would buy more time. Taxpayers cannot be dismissed as cynics if they assume that, faced with such incentives, industry would be tempted to spend as much time and as much taxpayers' money as they could get away with on such demonstrations.

II. Relationship of the DOE Clean Coal Program to the Special Envoys Report

The January 1986 Special Envoys Report recommended a five-year, $5 billion control technology commercial demonstration program, with half of the funding from the federal government and the other half from industry. On March 19, 1986 President Reagan stated "I fully endorse the report and will shortly issue a press statement to this effect."[11] The Press Statement referred to by the President discussed pre-existing U.S. research, development and control spending and stated "as the Joint Report notes, more needs to be done."[12] The Statement went on to state "the Administration will seek to provide in the future the funding recommended in the Joint Report."

Given these statements the U.S. and Canadian public were entitled to believe that President Reagan had committed to seek and spend $2.5 billion in federal funds over the next five years for commercial demonstration projects meeting the criteria of the Envoys Report. However, in the last few months the Administration has revealed that it will seek only $350 million in additional demonstration funding over the next five years.[17] Rather than seeking a full $2.5 billion in federal funding for demonstrations the Administration is claiming that the combined total of federal and non-federal investments since 1986 in "research, development and demonstration of new technologies" will exceed $5 billion.[18]

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[11] White House Office of the Press Secretary, "Remarks By the President," March 19, 1986.

[12] White House Office of the Press Secretary, "Statement by the Principal Deputy Press Secretary," March 19, 1986.

Let me say that I do not think that $2.5 billion in federal funding is required to commercially demonstrate the relatively few techniques that are ready for demonstration and otherwise meet the criteria of the Envoys Report. However, having committed to seek such funding, the U.S. should honor that commitment or should discuss with the Government of Canada some alternative U.S. proposal on acid rain to replace last year's commitment.

It does not serve the credibility of the Administration domestically or in Canada to claim that previously programmed expenditures covering a wide range of technology-related research satisfy the commitment made by the President last March. Two, arguably three, of the nine projects selected by DOE last August in "round one" of the clean coal program meet the commercial and retrofit criteria of the Envoys Report. According to the CRS analysis of these projects, the federal share amounts to $23.6

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[17] The Budget for Fiscal Year 1988 at page 2-18.

[18] Id. (emphasis added); and see DOE, America's Clean Coal Commitment, February 1987.

million.[18] Assuming that all of the additional $350 million to be requested by the Administration is awarded to projects meeting the Envoys Report criteria, the total federal commitment since the Envoys Report would be less than $400 million.

In my opinion the proper remedy for this failure to honor last year's commitment is for the Administration to change its position on the need for acid rain control legislation. When the President meets with Canadian Prime Minister Mulroney in April Mr. Reagan should tell our ally that for the good of the U.S. and Canada he will seek a new U.S. law to reduce acid rain-causing emissions.

Whether the Administration changes its policy or not, we urge the Congress to pass an acid rain control law without delay. We have the means now to attack this major environmental problem; the claim that we should wait for a "better solution" is a prescription for inaction.

Thank you. I'll be happy to answer your questions.

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[18] See January 1987 CRS report, supra, at 26.

TABLE 1

ANNUAL CONSUMPTIONS AND GENERATIONS FOR A 500 MW COAL FIRED POWER PLANT

Coal Feed (dry tons/yr)	1,177,300
Limestone Consumption (dry tons/yr)	142,875
Flyash Generated	126,320
Uncontrolled SO_2 (dry tons/yr)	89,480
SO_2 Emission with 75% Removal (tons/yr)	22,370
Gypsum Generated (dry tons/yr)	180,600

Assumptions:

500 MW generating capacity firing 3.8% sulfur coal with 13.4% ash and a heating value of 11,200 Btu/lb. 70% annual load factor and 75% overall SO_2 removal.

Table 2 Total FGD Plant Investment (actual costs)

Medium to High Sulfur Coal, Limestone Scrubbing with Forced Oxidation and Sludge Fixation for Landfill Disposal
1983-1984 Dollars

Average plant size is 600 MW	Avg. 3 Plants
Alkali Feed & Prep.	$ 12.06/kw
Gas Handling	11.35
SO_2 Absorber	33.29
Slurry Oxidizer	2.42
Waste Handling	18.63
Foundations	2.18
Buildings	4.60
Miscellaneous	0.77
Engineering & Project Management	10.39
Construction Super.	2.17
Startup	0.51
Total Process Capital (TPC)	$ 101.71/kw
General Site Work	16.00
A-E Fees @15% of TPC	15.26
Sub-Total	$ 132.97/kw
5% Contingency	6.65
Total Plant Cost	$ 139.62/kw
Interest During Const. (12.5%) & Escalation (8.5%); Factor 0.0567 of Total Cost	7.91
Total Plant Investment	$ 147.53/kw

Table 3 Retrofit Slip-Stream Scrubbing Costs

500 MW Unit, Firing High Sulfur Coal
Capital Cost = $147.5/kw of Scrubbed Capacity
Operating Cost = 6.17 Mills/kwh of Scrubbed Capacity

Overall Eff. (%)	Scrubber Module Eff. (%)	Reheat Bypass (%)	Scrubber Flow (ACFM Sat.)	Emission Lbs/mm btu)	Stack Temp. (°F)	Reheat ΔT (°F)	Capital Cost (1) ($/kw)	Operating Cost (2) (Mills/kwh)
50	90.0	44.4	2 x 498,221	4.63	211	84	83.4	3.43
50	95.0	47.4	2 x 472,946	4.63	217	90	77.8	3.24
50	97.5	48.7	2 x 460,820	4.63	219	92	75.7	3.16
60	90.0	33.3	2 x 599,055	3.71	189	62	98.4	4.11
60	95.0	36.8	2 x 567,536	3.71	196	69	93.2	3.90
60	97.5	38.5	2 x 552,963	3.71	199	72	90.7	3.79
70	90.0	22.2	2 x 698,910	2.78	168	41	114.8	4.80
70	95.0	26.2	2 x 662,125	2.78	176	49	108.9	4.56
70	97.5	28.2	2 x 645,147	2.78	180	53	105.9	4.43
75	95.0	21.1	2 x 709,422	2.32	166	39	116.4	4.87
75	97.5	23.1	2 x 691,229	2.32	170	43	113.4	4.74
80	97.5	17.9	2 x 737,311	1.85	160	33	121.1	5.06
80	98.5	18.8	2 x 729,825	1.85	162	35	119.8	5.01
90	90.0	0	2 x 896,601	0.93	127	0	147.5	6.17

(1) Based upon 500 MW Generating Capacity
(2) Based upon 500 MW Generating Capacity and 6,132 Hrs/Yr.

Table 4 Annual 1st Year Operating Costs

500 MW Plant, High Sulfur Coal

Plant Investment = $150 x 1000 x 0.15/6,132 =	3.669 Mills/kwh
Consumables from Table 2 (1)	1.955
Additional DBA for 95% Efficiency Scrubbing	0.380
Manpower = $50,000 x 10/(500 x 6,132) =	0.163
Total Annual Cost (First Year)	6.167 Mills/kwh = 0.6167 ¢/kwh

Assumptions:

Fixed Charge Rate = 15%/yr.
Operating Labor = $18.30 with 30% overhead = $50,000/yr.
Operating Hrs. Per Year = 24 x 365 x 0.7 = 6,132 hrs/yr.
Manpower Requirements = 2 men/shift; 5 shifts = 10 men

(1) Landfill disposal of flyash and sludge included.

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March 9, 1987

The Honorable G.J. Mitchell
Chairman
Senate Subcomittee on
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176 Senate Russell Office
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Dear Senator ~~Mitchell~~, George.

We are very pleased that the Senate Subcommittee on Environmental Pollution is holding hearings on proposed acid rain control legislation. It is my pleasure to provide background information on the issue of particular concern at this week's hearing--the relationship between the U.S. Department of Energy's Clean Coal Technology (CCT) Program and the Joint Report of the Special Envoys on Acid Rain. If it would be helpful, I would be pleased to have this letter included in the permanent hearing record.

As you know, the Envoys' Report was the product of a year-long effort on the part of Drew Lewis, appointed by President Reagan, and William Davis, appointed by Prime Minister Mulroney, to study the acid rain problem and develop a plan to address it that would be acceptable to both Canada and the U.S., given the differing economic, social, and political implications of the problem in our two countries. As a result of their study, the Special Envoys concluded: "Acid rain is a serious environmental problem in both the United States and Canada...(and) a serious transboundary problem."

To begin the process of addressing the problem, the Special Envoys recommended that the U.S. implement a five-year, $5 billion commercial

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demonstration program to develop a menu of innovative, economically efficient technologies for controlling SO_2 and NO_x emissions. Specific criteria--including retrofitability, use of high-sulfur coal, and impact on transboundary emissions--were recommended for evaluating the suitability of proposed projects for government funding under this program.

Both President Reagan and Prime Minister Mulroney fully endorsed the Envoys' Report. My Government viewed the endorsement of the Special Envoys' recommendations as an important first step in bringing about significant, near-term reductions in U.S. pollutants which are now dispersed into Canada. Such reductions have been deemed essential by scientific bodies such as the Royal Academy of Sciences in Canada and the National Academy of Science in the U.S., if sensitive forests, soil, and surface waters in Eastern North America are to be protected from the environmental damage caused by acid rain.

In August of last year, DOE selected nine projects to be eligible for the $400 million made available by Congress for fiscal years 1986-1988 under the CCT Program. Shortly thereafter, DOE released a Report to Congress on the relationship between the projects selected and the recommendations of the Envoys' Report. While recognizing the differences in the goals of the CCT program and the program recommended by the Special Envoys, DOE concluded that "many of the technologies selected under the CCT Program are consistent with technologies which would have been selected if one followed the recommendations in the (Special Envoys' Report)."

In January 1987, the Administration took DOE's assessment one step further. Its proposed Budget for Fiscal Year 1988 recalls President Reagan's endorsement of the Special Envoys' Report and states that the commitment of already appropriated $400 million for the CCT Program was "a first step in carrying out the Envoys' recommendations." The budget proposes an additional $350 million in federal spending under the CCT Program, with at least as much funding to be provided by the private sector, "in response to the recommendations in the Envoys' Report." Noting additional state and private clean coal programs, the Administration concludes: "Together, the Federal and non-Federal investments beginning in 1986 constitute

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a national effort exceeding $5 billion in research, development, and demonstration of new technologies."

Because of the seriousness with which my Government views the Envoy process and the importance to Canada of its ultimate success, Environment Canada undertook extensive analysis of two issues--the DOE claim that the nine CCT projects satisfy the Envoys' recommendations and the Administration's suggestion in the FY 1988 budget proposal that current programs fulfill President Reagan's commitment to implement the Envoys' Report. Environment Canada's findings sharply contrast with DOE's and the budget proposal's conclusions. With respect to the particular projects selected in the first round of the CCT program, Environment Canada found:

- The nine projects selected might, if they displace production from existing plants, reduce U.S. SO_2 emissions by up to 65,000 metric tonnes. (In 1984 total U.S. SO_2 emissions were 21.4 million tonnes.)
- The projects will make no significant near term contribution to reducing transboundary emissions.
- The projects have very limited early retrofit potential; the impact of the new technologies on electric utility emissions will be negligible until after the year 2005.
- Only two of the nine selected projects come close to meeting the Special Envoys' recommendations and criteria.

It is worth noting that a recent Congressional Research Service (CRS) analysis of the CCT Program concurs with the conclusions of Environment Canada's studies. Specifically, it found that only three of the nine projects selected possibly meet the Envoys' Report criteria, and one of those three is so small that no emissions reductions can be expected from it. The total cost of the three projects is only $52 million. According to the CRS, "To achieve the goals of the Envoys' Report would require an integrated approach to clean coal technology demonstration focussed on the

...4

Envoys' recommendation and its goals. Such a program does not currently exist."

Environment Canada also assessed the various clean coal initiatives mentioned in President Reagan's recent budget proposal, based on information provided by DOE. It concluded:

- Only $1.7 billion of the proposed $5 billion in federal, state, and private expenditures appear to meet most of the Special Envoys' technical criteria.
- The potential reduction in transboundary pollution resulting from this spending is insignificant and will not alleviate the damage currently being caused in Canada by U.S. emissions of SO_2.
- In the absence of an acid rain control program, significant emissions reductions resulting from the currently planned clean coal technology initiatives or existing air pollution control programs are at least 25 years away.

Based on these findings, it is our view that the current U.S. clean coal technology program does not meet the objectives of the Envoys' Report or still Canadian concerns about acid rain. However, bearing in mind the full endorsement of the Lewis/Davis Report by the President and pursuant to the Vice President's recent visit to Ottawa, it remains the hope and expectation of the Canadian Government that the Administration will take steps to fulfill Mr. Reagan's commitment.

We welcome the Administration's proposal to focus new rounds of CCT project selection on criteria more in keeping with the Envoys' objectives. I want to stress that Canada is still firmly committed to the view that substantial near-term reductions in the transboundary flow of SO_2 emissions--on the order of 50%--are necessary if sensitive aquatic and terrestrial resources in Eastern North America are to be protected. Carrying out the Envoys' Report is only one step in bringing about these reductions.

Environment Canada's reports are enclosed. We would have no objection to their being included in the hearing record, if the Committee so desires.

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I have followed the hearings that your subcommittee held earlier this year and am aware that questions have been raised regarding Canada's efforts in recent years to bring about emissions reductions. In that connection, I thought it might be useful for you to see the enclosed comparison of SO_2 emissions reductions that have taken place in the U.S. and Canada since 1970, when both countries adopted their respective Clean Air Acts. (Canada's was enacted in early 1971.) This paper, which shows overall emissions in the two countries and a breakdown by industrial sector, demonstrates that Canada has achieved reductions of 40% over the last decade and a half; since 1980, the base year for the legislative proposals now before the Congress, Canadian emissions have decreased by 14%.

The reductions in Canada on a percentage basis have been significantly greater than those in the U.S. over the same periods. It is particularly interesting to note that while Canada has decreased emissions from its major polluting sector--non-ferrous smelters--by 53% from 1970-1984, U.S. electric utilities, the primary source of emissions in the U.S., have achieved only an 8% reduction over the same period.

Notwithstanding the reductions already achieved, Canada recognizes the need to go still further. In September 1984, Prime Minister Mulroney committed Canada to an additional program of emissions reductions, with the goal of bringing about a 50% decrease in emissions over the next decade from 1980 base levels--from 4.6 million tonnes in 1980 to 2.3 million tonnes in 1994. In 1985, the Federal Government reached agreement with the provinces of Eastern Canada that they would implement programs within their respective jurisdictions to bring about these reductions. These programs on the provincial level are almost entirely in place.

At the same time, the Prime Minister announced the adoption of tighter emissions standards for the transportation sector. As of September 1987, new cars sold in Canada must meet NO_x emissions standards

...6

equivalent to those in the U.S. Further, by December 31, 1989, trucks and buses must cut NO_x emissions by 14%, to the EPA standards for heavy duty vehicles which were announced in March 1985.

A more detailed description of the Canadian acid rain control program is enclosed. We are very proud of the emissions reduction efforts undertaken thus far by the provincial governments and Canadian industry, and we are committed to seeing the current acid rain control program through to its completion.

In closing, I would like to express our deep appreciation to you and to other members of the Senate Environment and Public Works Committee for your past and current efforts to seek a solution to this very serious environmental problem which affects both our countries. We wish you well in your current attempt to develop a viable legislative package that will accommodate the admittedly complex regional interests involved in this debate. I am happy to offer Canada's full cooperation in your efforts and would be pleased to share any research, modelling data, or additional details on the Canadian clean air program that you believe would be helpful. If we can be of assistance to you in any way, please do not hesitate to contact me.

Sincerely,

Allan Gotlieb
Ambassador

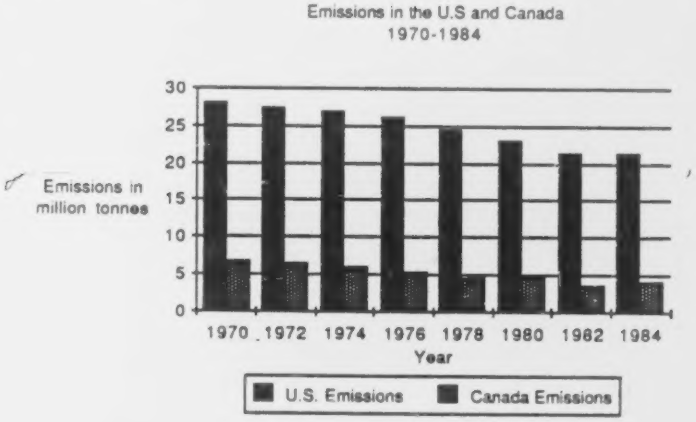
cc. Senator Burdick
Senator Stafford
Senator Chaffee
Members of the Senate Subcommittee on Environmental Pollution

SO_2 Emissions in Canada and the United States since 1970

The following material provides comparative data on SO_2 emissions reductions in the U.S. and Canada since the Clean Air Acts of each country went into effect, in 1970 and 1971 respectively.[1] It compares the overall percentage reduction in the two nations from 1970-1984, and also provides breakdowns of that reduction over the period 1970-1980, and the period 1980-1984.

I. Overall SO_2 Emissions Reductions

The following chart shows total emissions in the U.S. and Canada every two years since 1970:



SO_2 emissions in the U.S. declined from 28.2 million metric tonnes in 1970 to 21.4 tonnes in 1984, a reduction of 24%. An 18% reduction was accomplished from 1970 to 1980; between 1980 and 1984, emissions decreased by 8%.

In Canada, emissions decreased by 40% between 1970 and 1984, from 6.7 to 4 million tonnes. A 30% decrease took place between 1970 and 1980. Emissions in 1984 were down 14% from 1980 levels.

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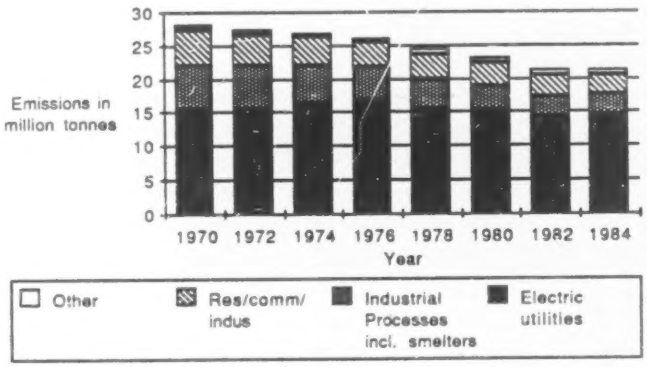
[1] U.S. data is taken from U.S. Environmental Protection Agency, National Air Pollutant Emission Estimates, 1940-1984, at 2, 12 (Jan. 1986). Canadian data was supplied by Environment Canada. Canadian figures for 1982 and 1984 are estimates only.

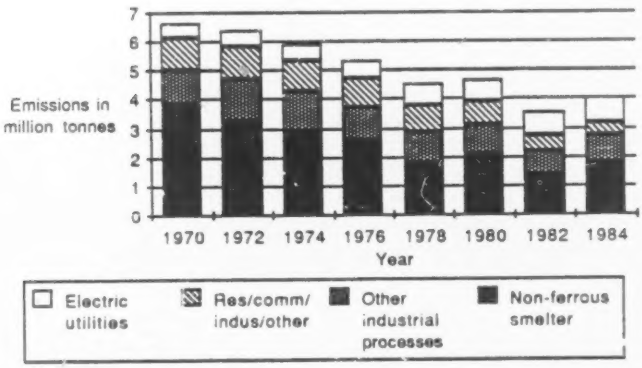
II. Reductions by Source Category

The following charts illustrate the emissions of the U.S. and Canada according to the source of those emissions:

U.S. Emissions by Source



Canadian Emissions by Source



As the chart demonstrates, the Canadian emissions reduction program between 1970 and 1984 has concentrated on the largest source category of

SO_2 emissions--non-ferrous smelters. This category, which accounted for 57% of all Canadian emissions in 1970, has reduced emissions by 53%--from 3.8 million tonnes in 1970 to 1.8 million tonnes in 1984. This has enabled Canada to achieve its overall reduction of 40% over the same period.

In the U.S., the largest source category of SO_2 emissions is electric utilities, accounting for 56% of all emissions in 1970. Emissions in this category declined 8% from 1970-1984, from 15.8 million tonnes to 14.5 million tonnes. As noted earlier, when all sources are included, SO_2 emissions in the U.S. declined by 24%.

III. Reductions by Province

The following table shows SO_2 emissions in Canada broken down by province (the amounts shown are in kilotonnes):

Province	1970	1972	1974	1976	1978	1980	1982	1983[2]
Ontario	3226	2673	2311	2225	1595	1772	1134	1244
Quebec	1309	1351	1335	1145	1131	1098	888	792
Manitoba	760	719	714	591	487	483	362	412
Alberta	623	757	656	536	551	599	526	546
BC, NWT, Yuk.	362	431	408	374	263	169	141	152
Nova Scotia	144	163	170	171	175	192	179	175
New Brunswick	133	178	152	162	191	219	206	175
Saskatchewan	56	52	55	53	63	54	83	94
Newfoundland	54	40	68	53	53	56	42	36
P.E.I.	9	10	10	9	6	5	3	2
Total	6676	6374	5879	5319	4515	4647	3564	3628

The table shows that the provinces from which the vast majority of Canadian SO_2 emissions emanate have all achieved substantial reductions since the Canadian Clean Air Act was implemented. Ontario, the single largest source of Canadian emissions, accounting for 48% of national emissions in 1970, reduced emissions by 61% between 1970 and 1983.

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[2] 1983 is latest year for which a province by province breakdown is available. Totals vary slightly from source breakdown because of rounding.

Ontario, Quebec, and Manitoba were responsible for 79% of Canadian emissions in 1970. These three provinces had reduced emissions by 53% by 1983. Eastern Canada, which includes all provinces east of the Manitoba/Saskatchewan border and which accounted for 84% of total Canadian emissions in 1970, reduced emissions by 50% over the same period.

Environment Canada Environnement Canada

STOP ACID RAIN

MEDIA BACKGROUNDER

CANADIAN ACID RAIN ABATEMENT PROGRAM PROGRESS REPORT

In February 1985, the federal government reached an agreement with the seven provinces east of Saskatchewan on the need to reduce total Canadian sulphur dioxide emissions to 2.3 million tonnes per year and to a preliminary series of limits to provincial emissions towards this objective. The provinces agreed to enforce these limits through their own legislation and to achieve them by 1994 at the latest.

Province	1980 Base Case (tonnes)	Emission Objectives (tonnes)
Manitoba	738,000	550,000
Ontario	2,194,000	1,030,000
Quebec	1,085,000	600,000
New Brunswick	215,000	185,000
P.E.I.	6,000	5,000
Nova Scotia	219,000	204,000
Newfoundland	59,000	45,000
Total	4,516,000	2,619,000

The governments committed themselves to allocating the remaining emission reductions required in time to achieve the overall goal by 1994. As of January 1987, the total emission objectives have been reduced to 2,475,000 tonnes in accordance with the following actions.

Quebec and Ontario have already introduced regulatory programs. Quebec will achieve emission reductions of 45 per cent by 1990. Ontario will achieve its emission reduction of 60 per cent - 10 per cent more than it originally committed to - by 1994. Manitoba recently issued draft regulations to achieve its 25 per cent reduction in emissions by 1994. Newfoundland and Prince Edward Island have air pollution control initiatives that will achieve the 25 per cent and 10 per cent reductions required respectively by 1994. Regulatory and program measures to achieve more than 90 per cent of the emission reductions required under the Canadian acid rain abatement program are now in place.

Canada

The federal government, for its part, made five commitments in March 1985 when the Canadian acid rain abatement program was announced:

- assure $25 million for technology development and demonstration at non-ferrous smelters;
- provide up to $150 million to cost-share smelter modernization/pollution abatement initiatives;
- assure $70 million for demonstration of cleaner, more efficient use of coal;
- guarantee $18 million per year for acid rain research and monitoring;
- adopt tough emission standards for new cars effective September 1987.

Through the Department of Regional Industrial Expansion's Industrial and Regional Development Program, the federal government has assisted Hudson Bay Mining and Smelting in Manitoba to demonstrate commercially a new process that could reduce emissions from this plant by about 35 per cent. Under the same program, INCO and Falconbridge in Ontario are being assisted in the commercial demonstration of technologies in time for the December 1988 decisions called for in Ontario's regulations.

To date, only Noranda has submitted a request for financial assistance for smelter modernization/ pollution abatement. A cost-sharing agreement with Quebec and Noranda is expected to be concluded shortly.

Substantial progress has also been made under Energy, Mines and Resources' Coal Utilization Demonstration Program. Alternative coal combustion systems, including fluid bed combustion, coal-water mixtures, coal beneficiation and improved burner systems, have advanced to the point where they can be considered for commercial use.

The federal government's research and monitoring program has also produced some significant findings. Studies in Nova Scotia have shown that the emission reductions that have taken place over the past 15 years or so have cut the acid deposition in some areas to less than 20 kilograms per hectare per year --the level required under the abatement program. The rivers in those areas are starting to show signs of chemical recovery. Not only is this good news, but it clearly demonstrates Canada is on the right track with its abatement program and objectives.

In order to reduce NO_x emissions from automobiles, Canada has adopted tougher emissions standards, effective September 1987. New heavy-duty vehicle emissions standards will be brought about in a two-phase approach. The effective date for these new standards will likely be December 1, 1988.

Once fully implemented, the Canadian acid rain abatement program is estimated to cost about $500 million annually.

Not only will the Canadian acid rain abatement program reduce the damage Canada is doing to itself, it will also reduce the transboundary flow of air pollution from Canada into the eastern United States. In 1980, the transboundary flow from Canada to the United States was about 1.5 million tonnes. By 1994, this will be reduced to about 0.8 million tonnes.

Sulphur dioxide emissions in eastern Canada were about 3.2 million tonnes in 1984.

Environment Canada
Environnement Canada

STOP ACID RAIN Canada

PRELIMINARY ASSESSMENT OF PROPOSED U.S. CLEAN COAL TECHNOLOGY RESEARCH AND DEVELOPMENT AND DEMONSTRATION INITIATIVES BETWEEN 1986 AND 1992

OTTAWA, CANADA
JANUARY 1987

Canada

SUMMARY

In January 1986, the Special Envoys on Acid Rain called for the implementation of a five-year, $5 billion U.S. program for the commercial demonstration of control technology in order to increase the range of available, cost-effective control options, and thus make it easier to formulate an acid rain control plan that would have broad public appeal in the United States. The Special Envoys also indicated that such a program should result in some near-term reductions in U.S. emissions affecting Canada.

President Reagan's 1988 budget proposal has been advanced as a U.S. response to the President's endorsement of the Special Envoys' report.

This assessment analyzes the current U.S. clean coal technology initiatives against the Special Envoys' criteria regarding the program for the commercial demonstration of control technology

The key preliminary conclusions are as follows:

- the U.S. clean coal technology initiatives, currently planned, will not provide any measurable reduction in the transboundary flow of U.S. air emissions affecting Canada between now and 1995;
- even after 1995, in the absence of a U.S. acid rain control program, neither the currently planned U.S. clean coal technology initiatives nor existing air pollution control programs will provide any significant reduction in U.S. transboundary air pollution flows for at least the next 25 years;
- the U.S. clean coal technology initiatives could result in cleaner, more cost-effective technologies being commercially available and competitive within the next ten years;
- about $5 billion in U.S. federal, state and private sector expenditures appear to be directed at demonstrating cleaner, more cost-effective technologies and in so doing, these expenditures meet one or more of the Special Envoys' criteria; and,
- while about $1.7 billion of the expenditures appear to meet most of the Special Envoys' technical criteria, the potential reduction in U.S. transboundary flows will be insignificant and will not alleviate the damage being caused in Canada.

ENVIRONMENT CANADA'S PRELIMINARY ASSESSMENT OF PROPOSED U.S. CLEAN COAL TECHNOLOGY RESEARCH AND DEVELOPMENT AND DEMONSTRATION INITIATIVES BETWEEN 1986 AND 1992

INTRODUCTION

In January 1986, the Special Envoys on Acid Rain called for the implementation of a five-year, $5 billion commercial-scale technology demonstration program in order to increase the range of available, cost-effective control options, and thus make it easier to formulate an acid rain control plan that would have broad public appeal in the United States.

The Envoys recommended that several criteria be considered in undertaking such a program:

- projects should result in significant emission reductions (measured as a percentage of pollutants removed);
- preference should be given to projects that achieve emission reductions most cost-effectively;
- more consideration should be given to projects that demonstrate technologies capable of being retrofitted to sources that contribute significantly to transboundary air pollution;
- special consideration should also be given to technologies applicable to sources that use high-sulphur coal; and,
- projects should result in some near-term reductions in U.S. emissions affecting Canada.

President Reagan's 1988 budget proposal indicated that the United States would spend more than $6.8 billion between 1986 and 1992 on clean coal technology projects. The following assessment is based on information provided to Canadian officials by U.S. Department of Energy (U.S. DOE) representatives. As additional information may be forthcoming, the assessment's analysis and conclusions must be considered preliminary and subject to possible revisions.

U.S. PROGRAM: AN OUTLINE

Federal Research and Development

Federal research and development initiatives involve work by the U.S. DOE and U.S. Environmental Protection Agency (EPA) on advanced combustors (slagging and fluid bed), alternative fuels (coal-oil and coal-water mixtures), coal liquefaction, coal cleaning, flue gas and gas stream clean-up, magnetohydrodynamics and coal gasification. The status of these initiatives ranges from proof-of-concept to small pilot-scale testing.

Total spending between 1986 and 1992 is estimated at $690 million, based on budget projections.

Federal Demonstrations

Current and planned federal demonstration initiatives include: U.S. DOE Clean Coal Technology Program, Phases I, II and III; other U.S. DOE demonstrations; EPA demonstrations; Department of Treasury demonstrations; and Tennessee Valley Authority demonstrations.

Under Phase I of the U.S. DOE Clean Coal Technology Program, nine projects have been selected for negotiation with the private sector. This phase was open to all technologies, all coals, all markets and both new and retrofit applications. The program predates the Special Envoys' report. Expenditures are forecast at: federal -$396 million; state -$32 million; and private sector -$567 million.

Phase II of the Clean Coal Technology Program is aimed at emerging technologies capable of retrofitting, repowering or modernizing existing facilities; it includes the Special Envoys' criteria in the solicitation statement. The 1988 budget includes $50 million and $100 million for 1988 and 1989, respectively. Those funds must be at least matched by private-sector expenditures. Responses to the program solicitation notice were due by 12 January 1987. Subject to appropriations, the U.S. DOE could issue formal project solicitations in 1988.

Phase III of the Clean Coal Technology Program will likely be aimed at emerging technologies capable of retrofitting, repowering or modernizing existing facilities using high-sulphur coal that were not advanced enough to respond to Phase II. The Special Envoys' criteria would probably be included in the project solicitation. The U.S. DOE has not sought appropriations for Phase III, but it forecasts expenditures of $50 million, $100 million and $50 million for 1990, 1991 and 1992, respectively. Those funds must be at least matched by private-sector contributions.

The other U.S. DOE demonstration projects include the "Kilngas" project (coal gasification) and a 160-MW atmospheric fluid bed combustion unit. Total expenditures are planned at $436 million until 1992.

The U.S. EPA projects include demonstrations and basic research on limestone injection multi-stage burner (LIMB) technology, at two commercial-size units. Total expenditures are planned at $61 million.

The U.S. Department of Treasury initiatives involve price guarantees that will be paid out on two existing Synfuels Corporation projects: the DOW Synfuels coal gasification project and the integrated combined cycle coal gasification project at Daggett, California (Cool Water Project). Total expenditures are estimated at $1098 million.

The Tennessee Valley Authority initiatives include a 20-MW atmospheric fluid bed combustion unit to be used as the basis for a 160 MW unit (see other U.S. DOE demonstrations above) and an advanced spray dryer flue gas desulphurization unit. Total expenditures are forecast at $43 million.

State Programs

The state programs component is very incomplete. Program descriptions are available only for Ohio and Illinois, although Kentucky, New York and Pennsylvania also have programs. Ohio's program is designed to provide support for commercial demonstration of new technologies that could be applied to existing and new facilities and that exceed the environmental performance and cost-effectiveness of existing technologies. Thirteen projects are under way at present. Illinois has a similar program under way, with eight projects. Total state expenditures are currently estimated at $272 million. Private-sector contributions to these programs remain to be determined; they will probably amount to several hundred million dollars.

Private Demonstrations

The Electric Power Research Institute (the research association of the U.S. utility industry) has five demonstration projects under way. These include:

- a 125-MW atmospheric fluid bed conversion of an existing conventional pulverized coal unit at Northern States Power, Minneapolis, Minnesota;
- a 110-MW circulating atmospheric fluid bed unit at Nucla, Colorado;

- a coal cleaning test facility at Homer City, Pennsylvania, to accelerate the use of new and improved coal cleaning technology;
- a high-sulphur test centre at Niagara, New York, to improve SO_2 removal efficiency, by-product quality, energy requirements and water requirements for flue gas desulphurization technology; and,
- a Shell Oil Coal Gasification Demonstration plant at Houston, Texas, to process a broad range of coals.

Other private demonstrations include: one coal liquefaction facility in Colstrip, Montana, and 16 atmospheric fluid bed units in various configurations and sizes located in the eastern United States. Total expenditures are estimated at $2209 million.

Private Research and Development

The Electric Power Research Institute research and development work includes initiatives on: advanced SO_2, NO_x and particulate control equipment; advanced combustion techniques; and advanced coal cleaning.

No information is yet available on the Gas Research Institute research and development initiatives.

Total private-sector research and development expenditures are estimated at $329 million by 1989.

The planned spending on U.S. clean coal technology research and development and demonstration is as follows:

Category	Planned Expenditures ($ million)			Timing	Number of Projects
	Federal	State	Private		
1. Federal Research & Development					60 +
DOE	677	-	-	1986-92	
EPA	6	-	7	1986-92	
2. Federal Demonstration					
DOE Clean Coal I	396	32	567	1986-89	9
DOE Clean Coal II	150	?	150	1988-89	?
DOE Clean Coal III	200	?	200	1990-92	?
DOE Other	52	39	345	1986-92	2
EPA	20	-	41	1986-?	2
Treasury	740	-	358	1986-?	2
Tennessee Valley Authority	20	-	23	1986-?	2
3. State Programs					
Illinois, Kentucky New York, Ohio Pennsylvania	-	272	?	1986-?	21 +
4. Private Demonstration					
Electric Power Research Inst.	-	-	353	1986-89	5
Other	-	-	1856	1986-?	17
5. Private Research & Development					
Electric Power Research Inst.	-	-	289	1986-89	?
Gas Research Inst.	-	-	40	1986-89	?

The cost-sharing of these initiatives can be summarized as follows:

	Federal	State	Private	Total
Federal R&D	683	-	7	690 (10%)
Federal Demo's	1578	71	1684	3333 (49%)
State Programs	-	272	?	272 (4%)
Private Demo's	-	-	2209	2209 (32%)
Private R&D	-	-	329	329 (5%)
Total	2261 (33%)	343 (5%)	4229 (62%)	6833

ANALYSIS

A Canadian assessment of the U.S. clean coal initiatives must be undertaken from three perspectives. First, it must consider the extent to which the individual projects meet at least one of the Special Envoys' criteria. Second, it must examine the extent to which the program meets the Special Envoys' recommendation that it commercially demonstrate technologies, thereby increasing the range of available control options. Third, it must analyze the probable near-term reductions in U.S. emissions affecting Canada. This latter criterion is of the greatest importance to Canada.

Federal Research and Development

While much of the $690 million in expenditures appears to be directed at work that might eventually meet the Special Envoys' criteria related to significant reductions, cost-effectiveness and application to sources using high-sulphur coal, there are no projects that would result in commercial-scale demonstrations in the foreseeable future, nor will any of the expenditures result in near-term reductions in U.S. emissions affecting Canada. These expenditures, therefore, are judged not to meet the Special Envoys' criteria.

Federal Demonstrations

Eight of the nine projects selected under Phase I of the U.S. DOE Clean Coal Technology Program meet at least one of the Special Envoys' criteria related to significant emission reductions, cost-effectiveness or application to sources using high-sulphur coal. In Environment Canada's earlier analysis (Appendix #1), it was concluded that this program has only a few commercial-scale demonstrations and minimal emission reduction potential. Environment Canada estimates that these projects could reduce U.S. emissions by up to 65,000 tonnes per year. Although the precise effect is difficult to calculate accurately, it might reduce the transboundary flow of U.S. air pollution into eastern Canada by about 0.5 per cent.

It is assumed that projects under Phases II and III of the Clean Coal Technology Program will meet at least one of the Special Envoys' criteria, as the criteria are, or will be part of the project solicitations. If the projects are selected in a manner that provides for maximum reduction in transboundary flows of U.S. air pollution into eastern Canada, the expenditures contemplated ($700 million) could reduce this flow by a few per cent.

The other U.S. DOE demonstrations meet the Special Envoys' criteria concerning significant emission reductions and cost-effectiveness criteria but will do nothing to reduce the transboundary flow of U.S. air pollutants into eastern Canada.

The U.S. EPA limestone injection multi-stage burner (LIMB) demonstrations meet the Special Envoys' cost-effectiveness criterion, but are estimated to have only a very small impact on transboundary flow of U.S. air pollution into eastern Canada (a probable reduction of less than 0.1 per cent).

The U.S. Treasury Department demonstrations meet the Special Envoys' criteria relating to significant emission reduction and cost-effectiveness, but will have no near-term effect on the transboundary flow of U.S. air pollution. This fact is due to their locations, which are far removed from Canada (e.g. southern California).

The Tennessee Valley Authority demonstrations meet the Special Envoys' criteria relating to significant emission reductions and cost-effectiveness, but will have no impact on U.S. transboundary flows of air pollution, because of their small size and location.

State Programs

Virtually all of the known state-sponsored programs meet the Special Envoys' criteria concerning emission reductions and cost-effectiveness criteria. There is insufficient information available to determine the extent to which these initiatives will influence U.S. transboundary air pollution. However, due to the small size of many of the projects and the fact that they are not likely to displace load (production) from existing facilities, the overall emission reduction potential is judged to be marginal at best. This judgment could be revised, however, as more information becomes available.

Private Demonstrations

All of the Electric Power Research Institute demonstrations appear to meet the Special Envoys' criteria regarding significant emission reductions and cost-effectiveness. The atmospheric fluid bed retrofit project in Minneapolis should slightly reduce the flow of U.S. air pollutants into eastern Canada.

The 17 other private demonstration projects all appear to meet the Special Envoys' criteria relating to emission reductions and cost-effectiveness. Six of the 17 projects are of a size and location that might have an impact on transboundary air pollution; in the absence of detailed information, however, it is not possible to estimate the probable effects.

Private Research and Development

There is insufficient information to judge the extent to which the Electric Power Research Institute research and development work may meet the Special Envoys' criteria. There is no information on the Gas Research Institute initiatives.

Summary of Analysis

Category	Special Envoys' Criteria				
	Large % emission reductions	Cost Effectiveness	High Sulphur Coal	Commercial Scale Demo's	Trans-bound. Reduc.
Fed. R&D	N.A.	N.A.	N.A.	no	no
Fed. Demos	yes	yes	yes	some	min.
State Prog.	yes	yes	yes	some	min.
Private Demos	yes	yes	most	some	min.
Private R&D	?	?	?	no	no

It is currently estimated that about $5.3 billion in projected expenditures between 1986 and 1992 meet one or more of the Special Envoys' criteria. The federal, state and private sector breakdown of these expenditures is as follows: federal - $1.5 billion (28%); state - $0.3 billion (6%); and private sector -$3.5 billion (66%).

The number of projects and expenditures that appear to meet most of the technical criteria of the Special Envoys' recommendation are estimated at: 15 current projects (and perhaps also the Clean Coal Technology Program, Phases II and III) and expenditures of about $1.7 billion. The cost-sharing breakdown is: federal - $0.5 billion (27%); state -$0.04 billion (2%); and private sector - $1.22 billion (71%).

CONCLUSIONS

Sufficient information has been made available to arrive at a preliminary assessment of the extent to which currently planned U.S. clean coal technology initiatives meet the criteria and intent of the Special Envoys' recommendation for a control technology commercial demonstration program.

The United States is, undoubtedly, spending substantial amounts on clean coal technology research and development and demonstrations. Based on the available (but limited) information, it is estimated that \$5.3 billion of the \$6.8 billion in scheduled and proposed expenditures probably meet at least one of the Special Envoys' criteria. This estimate will change with the inclusion of private-sector contributions to state-sponsored demonstration projects.

The real question, however, is the extent to which the initiatives fulfill the Special Envoys' recommendation, which was that the program develop a range of commercially available, cost-effective control options upon which to formulate an acid rain abatement program, and to provide some near-term reductions in U.S. air emissions affecting Canada. Total expenditures that appear to meet the technical aspects of these requirements are estimated to be \$1.7 billion.

Most of the new technologies being developed and demonstrated will likely be commercially available for widespread use by 1995. This forecast assumes that the projects planned , will provide, within the scheduled timeframes, an acceptable data base to overcome concerns about performance and reliability. It can, therefore, be reasonably assumed that current and proposed U.S. initiatives have the potential, by 1995, to expand the range of cost-effective options upon which to formulate an acid rain control plan. In addition, the schedule could be accelerated if required.

With regard to the criterion of greatest importance to Canada, near-term reductions in transboundary air pollution from the projects themselves, the preliminary conclusion must be very pessimistic. Between now and 1995, the current and proposed U.S. clean coal initiatives would appear to do little, if anything, to reduce the flow of transboundary air pollution from the United States into Canada. The maximum reduction in transboundary flows of air pollution would probably be less than 100,000 tonnes per year. This figure represents about a 2.5-per-cent reduction from the 1980 calculated flow of 4 million tonnes.

Finally, some forecast should be made of the longer-term (i.e., post-1995) implications of the U.S. initiatives. Even in the absence of a legal requirement to do so, some of the technologies being demonstrated are likely to be implemented. Between 1995 and 2010, most of the coal-fired power plants currently operating in the eastern United States will become more than 30 years old. As a result, many of them will probably need major refurbishing. It is reasonable to assume that as their life expectancy is reached, the less efficient (and dirtier) conventional technologies could be replaced with newer, more efficient and cleaner technologies, if the latter can compete on a purely economic basis. To date, however, there are no reliable estimates of the market potential for the new technologies between 1995 and 2010.

In summary, the key preliminary conclusions are as follows:

- the U.S. clean coal technology initiatives, currently planned, will not provide any measurable reduction in the transboundary flow of U.S. air emissions affecting Canada between now and 1995;
- even after 1995, in the absence of a U.S. acid rain control program neither the currently planned U.S. clean coal technology initiatives nor existing air pollution control programs will provide any significant reduction in U.S. transboundary air pollution flows for at least the next 25 years;
- the U.S. clean coal technology initiatives could result in cleaner, more cost-effective technologies being commercially available and competitive within the next ten years;
- about $5 billion in U.S. federal, state and private sector expenditures appear to be directed at demonstrating cleaner, more cost-effective technologies and in so doing, these expenditures meet one or more of the Special Envoys' criteria; and,
- while about $1.7 billion of the expenditures appear to meet most of the Special Envoys'technical criteria, the potential reduction in U.S. transboundary flows will be insignificant and will not alleviate the damage being caused in Canada.

APPENDIX I

A Canadian Assessment of the Extent to which the Nine Projects Selected Under the U.S. Department of Energy's Clean Coal Technology Program Meet the Recommendation of the Special Envoys on Acid Rain on a Control Technology Commercial Demonstration Program

Environment Canada
Ottawa, Canada
November 1986

PREFACE

This report was prepared by Environment Canada as a preliminary assessment of the extent to which the nine projects selected under the U.S. Department of Energy's (U.S. DOE) Clean Coal Technology Program meet the criteria recommended by the Special Envoys on Acid Rain for a control technology commercial demonstration program.

The assessment is based on publicly available information on the nine projects, particularly that contained in the U.S. DOE's October 1986 Report to Congress on the Relationship between Projects for the Clean Coal Technology Program and the Recommendation of the Joint Report of Special Envoys on Acid Rain.

Discussions are continuing between Environment Canada and the U.S. DOE on the nature of initiatives under the Clean Coal Technology Program and other innovative technology development and demonstration programs in the federal state and private sectors.

INTRODUCTION

This report assesses the extent to which Canada believes the projects selected by the U.S. Department of Energy under the Clean Coal Technology Program (CCTP) meet the recommendation and criteria of the Special Envoys on Acid Rain on a control technology commercial demonstration program. The assessment is based on the information contained in the U.S. DOE's October 1986 Report to Congress on the Relationships Between Projects for the Clean Coal Technology Program and the Recommendations of the Joint Report of the Special Envoys on Acid Rain.

SPECIAL ENVOYS' CONTROL TECHNOLOGY COMMERCIAL DEMONSTRATION PROGRAM

Intent of the Program

From information contained in their report, the intent of the Special Envoys' recommendation for a control technology commercial demonstration program is quite clear. They concluded that "at the present time, there are only a limited number of potential avenues for achieving major reductions in acidic air emissions, and they all carry high socio-economic costs." Thus, "if the menu of control options were expanded, and if the new options were significantly cheaper yet highly efficient, it would be easier to formulate an acid rain control plan that would have broader public appeal." The Special Envoys also noted their recommendations "-must ... reduce the flow of airborne pollutants across our common border."

Other sections of the Special Envoys' report clearly indicate the body of data and discussion upon which the recommendation was based. The Special Envoys noted that they had met with:

- senior officials in Washington and Ottawa;
- U.S. Cabinet members and Canadian Cabinet ministers;
- U.S. and Canadian environmental officials;
- members of Congress and Parliament;
- U.S. governors and Canadian premiers;
- scientists and researchers in the United States and Canada;
- industrial leaders, notably those in the utility, coal mining and ore smelting sectors;
- representatives of organized labour, unions and concerned groups of citizens; and,
- leaders of environmental organizations.

The foregoing information leads to two inescapable conclusions as to the intent of the Special Envoys' recommendation for a control technology commercial demonstration program:

- after fully considering the federal, state and private-sector initiatives existing at the time of their report, the Special Envoys believed that an additional clearly focussed, co-ordinated and adequately funded effort was required; and,
- the Special Envoys believed that such a program should demonstrate, on a commercial scale, innovative technologies that could have substantial application in an acid rain control program, and that these demonstrations should result in near-term reductions in the transboundary flow of air pollutants.

Criteria for the Program

For the design of a program to meet these requirements, the Special Envoys recommended the following criteria:

- the level of effort should be five years and $5 billion, with one half of the funding being provided by the U.S. federal government;
- selected projects should have the potential for the largest emission reductions, measured as a percentage of SO_2 or NO_x removed;
- among projects with similar potential, funding should go to those that would reduce emissions at the cheapest cost per ton;
- more consideration should be given to projects that demonstrate retrofit technologies applicable to the largest number of existing sources that, because of their size and location, contribute to transboundary air pollution;
- the projects should result in some near-term reductions in U.S. emissions that affect Canadian ecosystems; and
- special consideration should be given to technologies that can be applied to facilities currently dependent on the use of high-sulphur coal.

ASSESSMENT

An assessment of the extent to which the nine projects selected under the U.S. DOE CCTP meet the Special Envoys' recommendation must be undertaken from two perspectives. First it must consider the extent to which the program as a whole meets the intent of the Special Envoys' recommendation. Second, it must assess the extent to which the individual projects meet the criteria established by the Special Envoys.

CCTP and Intent of the Special Envoys' Recommendation

In December 1985, the U.S. Congress made $400 million available for the U.S. DOE to undertake the CCTP " for the construction and operation of facilities to demonstrate the feasibility and future commercial applications" of such technologies. The U.S. DOE Report to Congress notes that "the CCTP projects will not be commercial until their demonstrations are completed and commercial size projects are subsequently constructed and operated by the private sector." Thus, by program definition and by acknowledgment in the U.S. DOE Report to Congress, the CCTP does not meet the intent of the Special Envoys' recommendation that the range of control options available to formulate an acid rain control plan be expanded through commercial-scale demonstration of innovative technologies within five years. With respect to reductions in emissions contributing to transboundary air pollution, the U.S. DOE Report to Congress acknowledges "this was not a factor in the evaluation of proposed projects under the CCT Program."

CCTP and the Special Envoys' Criteria

From the Canadian perspective, two of the Special Envoys' criteria are of paramount importance, and it is primarily against these that Canada judges the extent to which the individual CCTP projects meet the Special Envoys' recommendation. These criteria are:

- the extent to which the projects themselves will result in near-term reductions in U.S. air emissions that affect Canadian ecosystems; and
- the extent to which the projects selected demonstrate technologies that could be retrofitted to the largest number of existing sources that, because of their size and location, contribute to transboundary air pollution.

Unfortunately, the U.S. DOE Report to Congress gives rather short shrift to these criteria and provides only limited concrete information on which to base an assessment. For example, the report states that "five of the nine demonstration projects are expected to result in reduced emissions at the demonstration plant sites." **A Canadian assessment concludes that the nine projects under the CCTP might reduce U.S. emissions by up to 65,000 tonnes** (see attachment 1). This conclusion assumes that the demonstration projects would actually be displacing production from other existing production facilities. If the projects are research oriented and result in limited or no displacement of existing production, there may be no reduction, or even an increase, in emissions during the projects' lifetime. While the U.S. DOE Report to Congress is silent on this matter, **it is Canada's observation that these projects would make no significant near-term contribution to reducing SO_2 emissions that affect Canadian ecosystems.**

The extent of the projects' retrofit application to a large number of sources is also difficult to assess. The U.S. DOE noted that "five of the nine projects selected can be retrofitted to existing sources." The Special Envoys' criterion regarding retrofit application concerns not the question of whether the technologies can be retrofitted, but **specifically the extent to which they can be retrofitted to a large number of existing sources that, because of their size and location, contribute to transboundary air pollution.** Figure 3 in the U.S. DOE Report to Congress (attachment 2) provides the only concrete evidence on this question. It shows the potential impact of new technology versus current technology on projected utility SO_2 emissions. Canada assumes the figure relates to the technologies being demonstrated under the CCTP. No impact is noted for the new technologies until after the year 2005. **Canada concludes,** based on the data presented in figure 3, that **the CCTP projects have very limited early retrofit potential.**

CONCLUSION

Canada has established clear objectives on the acid rain issue. **Acid deposition must be reduced to less than 20 kilograms per hectare per year in all sensitive areas.** To achieve this level, **sulphur dioxide emissions in eastern Canada must be reduced by 50 per cent** (based on 1980 levels) and the **transboundary flow of pollution from the United States into Canada must be reduced by 50 per cent** (based on 1980 levels), from 4 million tonnes down to 2 million tonnes.

Canada measures any U.S. clean coal technology demonstration initiative primarily by the extent to which the technologies can be applied to the principal sources of emissions affecting Canada and by the extent to which the demonstration projects provide near-term reduction in the transboundary pollution flows.

From the U.S. DOE Report to Congress, Canada concludes that the projects selected under the CCTP do not meet the intent and criteria of the Special Envoys' recommendation on a control technology commercial demonstration program. Only two of the projects, the Babcock-Wilcox and, Energy and Environmental Research Corporation proposals, come close to meeting the Special Envoys' recommendation and criteria. As a result, the CCTP will not affect the range of control options available for formulating an acid rain control plan and will not have any near-term impact on transboundary air pollution.

ATTACHMENT 1

ESTIMATED EMISSION REDUCTIONS FROM NINE SELECTED PROJECTS UNDER U.S. DOE CLEAN COAL TECHNOLOGY PROGRAM (CCTP)

The following are optimistic estimates of the reductions in SO_2 emissions that could result from the nine selected CCTP projects after the 2-to 6-year demonstrations are complete. The estimates are based on the following assumptions:

- sulphur content of coal: 3.4%
- boiler heat rate: 12,000 BTU/kw-hr (both the demonstration boiler and the generation being replaced)
- coal heating value: 11,240 BTU/lb.

Project	Annual Emission Reduction (Tonnes/yr)
American Electric Power (Pressurized fluidized bed combustion - 70MW)	12,200
Babcock & Wilcox (Sorbent Injection - 105MW)	10,800
Energy & Env. Res. (Sorbent Injection - 117,80,40MW)	22,200
Coal Tech. Corp. (Slagging Combustor - 1T/hr)	--
Kellogg (Coal Gasification/ Combined Cycle - 60MW)	11,100
Gen. Electric (Coal Gasification/Gas Turbine - 5,55MW)	8,200
Energy Int'l (In-Situ Gasification - 200T/day)	--
Ohio-Ont. (Synfuel - 800T/day)	--
Weirton Steel (Ironmaking Demo.)	--
TOTAL	64,500

The estimates are very optimistic in that they assume these very small units will operate at 65% capacity factor once modified for demonstration. It is more likely they will be operated at much lower capacity factors for much of the projects' duration.

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STATE OF WYOMING
OFFICE OF THE GOVERNOR
CHEYENNE 82002

MIKE SULLIVAN
GOVERNOR

March 9, 1987

Subcommittee on Environmental Protection
of the Senate Committee on Environment
and Public Works
261 Dirksen Building
Washington, D.C. 20510

ATTN: Mr. R. Brent Erickson

Members of the Subcommittee:

I am pleased to have been asked to make some comments to the Committee and am disappointed that I could not appear in person. As a newly-elected executive of Wyming, my other commitments preclude my attendance. However, I did not want to miss the opportunity to present to you a clean coal technology which we in Wyoming are optimistic may not only spur this State's economic development, but also bolster the sagging economy of our entire nation by converting coal from all regions of the country to an economical, compliance, fluidic fuel.

My predecessor, Governor Ed Herschler, was approached by Carbon Fuels Corporation with regard to a demonstration facility necessary to commercialization of this technology. In response to the presentation, Governor Herschler was instrumental in persuading PacifiCorp, a large investor-held utility that services Wyoming, to dedicate coal, land, and a 100 Megawatt boiler at their Dave Johnston facility at Glenrock, Wyoming to participate in the commercial demonstration of the process, which, as I understand, is essentially 95% off-the-shelf technology. In addition, Governor Herschler made preliminary provisions for Carbon Fuels Corporation, by and through its subsidiary, Char-Fuels of Wyoming, Inc., to receive $4 million of Wyoming's share of Exxon Restitution Funds for use in retrofitting the Dave Johnston boiler. Governor Herschler made an enthusiastic commitment to commercialize this technology, which commitment I have supported.

During the last session, the Wyoming legislature, with the help of Carbon Fuels Corporation, passed legislation which allows monies from the State's Mineral Trust Fund to be utilized to sponsor clean coal technology which is expected to assist in stimulating economic development in the State. Of these funds, $10 million has been requested by Carbon Fuels for use in its Glenrock demonstration project. In addition, it is our understanding Carbon Fuels Corporation has commenced, or will shortly, an equity offering of $10 million to complete the funding for the project.

We in Wyoming are enthusiastic about the potential for Wyoming and the nation from this coal processing technology. I believe that it is imperative to adopt acid rain legislation which can recognize the benefits from cleaning up the coal rather than targeting only cleaning up the emissions from coal combustion and/or the associated effluents. The concept of refining coal with processes similar to refining petroleum makes a great deal of sense. The Charfuel plant, in addition to producing a clean, fluidic, uniform-burning material capable of oil-type transport and handling, is expected to produce value-added by-products which will help the economy of both Wyoming and the United States.

As Governor, I am enthusiastic about the prospect of being able to further develop one of Wyoming's (and the country's) most abundant resources to help balance our trade deficit. As an intermountain state, Wyoming's access to foreign markets for its coal, and especially the lower Btu Powder River Basin coal, has been substantially non-existent. By increasing the Btu content of the material and affording a fluidic transport, we can reach markets for our resource heretofore not available.

Additionally, the Charfuel process is designed to effect the production of methanol, an oxygen-rich fuel, from coal. This not only preserves our valuable natural gas (the standard methanol feed-stock), but also affords still another utilization of our country's abundant coal resource.

In conclusion, I would urge the Committee to seriously consider legislation which would recognize clean coal technologies such as those which Carbon Fuels will commercialize. By recognizing the ability to remove pollutants from the fuel and make them valuable by-products, we will have gone a long way to promote the efficient and effective utilization of coal. I ask other coal producing states to join with Wyoming in expanding our national coal market and utilizing one of our most abundant resources to encourage regional economic development, reverse our negative balance of trade, and put our miners back to work, while at the same time cleaning up our precious environment.

Thank you for your consideration.

Very truly yours,

Mike Sullivan

MS:rb